Appendix B

Letter of API Assistant General Counsel, David T. Deal, to Associate Director for Royalty Management, Lucy Querques Denett, November 4, 1999, on Implications of the August 1999 Jury Verdict in City of Long Beach v. Exxon Litigation.

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David T. Deal
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November 4, 1999

Lucy Querques Denett
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Dear Ms. Denett:

At the core of the MMS' rationale for the pending federal oil valuation rulemaking is the State of California's conviction that the oil industry has underpaid royalties through use of posted prices and that Alaska North Slope prices are a better measure of value for royalty purposes. While California enunciated this view over a decade ago before the original Royalty Management Advisory Committee (RMAC) in the proceedings leading up to the MMS' 1988 oil valuation rule, RMAC and the MMS then rejected it out of hand.

Although California did not challenge the final MMS rule, it did continue to press for reexamination of its valuation views and this persistence led to the Interagency Study issued in May 1996. With little input beyond California, the Study (wrongfully, we believe) adopted the California view on valuation and extrapolated it to leases outside California. This led directly to the pending MMS rulemaking and the continuing rhetoric that oil companies underpay their royalties.

Given the MMS' reliance on the California perspective in shaping its rulemaking, the administrative record should now include the August 30, 1999 decision in <u>City of Long Beach v. Exxon</u>, No. C 587 912 (Superior Court of the State of California). Although several companies chose to settle claims early on, Exxon chose not to and, after 25 years of litigation, obtained a jury verdict that upheld their valuation of California oil production for royalty purposes. The decision is significant because the upheld methodology did not involve use of Exxon's own posted prices but rather an average of other companies' posted prices, even those that had settled earlier.

The <u>Long Beach</u> decision is even more significant because the now discounted California view still pervades the entire MMS oil valuation rulemaking. For example, in May 19, 1999 testimony before the House Subcommittee on Government Management, Information and Technology (copy enclosed), the acting assistant secretary, Sylvia Baca, made it clear that the alleged royalty underpayments in California were the antecedent for a nationwide enforcement strategy and the pending oil valuation rulemaking.

In sum, the Long Beach decision is the latest and most significant development in a proceeding that is a part of the administrative record and has misshaped the MMS' approach to the present rulemaking. For this reason alone, the Long Beach decision itself is an important part of the administrative record. Moreover, when coupled with the extensive information the MMS received during its March-April 1999 workshops and subsequent public comment period, the Long Beach decision reinforces the wisdom of publishing a new oil valuation proposal.

If the erroneous core assumptions of the present proposal can be excised, and fresher, more accurate information added, the result can be a rule that is reasonably certain, simpler, fair and in conformance with existing mineral leasing statutes.

Sincerely,

David T. Deal

Appendix C

"The Royalty Bargain," by John Lowe, George Hutchison Professor of Energy Law, Southern Methodist University.

THE ROYALTY BARGAIN

by

John S. Lowe
George W. Hutchison Professor of Energy Law
January 28, 2000

A. Introduction

My name is John S. Lowe. I am currently the George W. Hutchison Professor of Energy Law at Southern Methodist University. I have worked as a law professor teaching and writing about oil and gas law for more than 25 years at SMU, the University of Tulsa, and the University of Toledo. I have been a Visiting Professor at the University of Texas, a Distinguished Visiting Professor at the University of Denver, and the Visiting Judge Leon Karelitz Chair in Oil and Gas Law at the University of New Mexico. I hold a B.A. in economics from Denison University and an LL.B. from Harvard University. I am admitted to practice law in Ohio, Oklahoma and Texas.

I am a Past Chair of the Section of Natural Resources, Energy and Environmental Law of the American Bar Association, a 13,000-member professional organization. I have served as Secretary and as a member of the Executive Committee of the Rocky Mountain Mineral Law Foundation; I am currently a Trustee of that organization. I am Treasurer of the Advisory Board of the International Oil and Gas Educational Center of the Southwestern Legal Foundation. I am a former Member of the Council of the Oil, Gas and Mineral Law Section of the State Bar of Texas. I have been honored by the National Association of Royalty Owners for service to its members.

I have written extensively about oil and gas law, including the royalty obligation. I am the author of OIL AND GAS LAW IN A NUTSHELL (West 3d ed. 1995). I am one of the editors (with E. Kuntz, O. Anderson, E. Smith and D. Pierce) of CASES AND MATERIALS ON OIL AND GAS LAW (West 3d ed. 1998), which is the most widely used law school casebook on the subject. I am Maintenance Editor of two major oil and gas law treatises, SUMMERS' OIL AND GAS LAW and KUNTZ' LAW OF OIL AND GAS, as well as the author of volumes 6, 7 and 7A of WEST'S TEXAS FORMS (3d ed. 1997) and the *Minerals, Oil and Gas* section of Vol. 28 of WEST'S LEGAL FORMS (3d ed. 1997). I am one of the Editors of the OIL AND GAS REPORTER, Matthew Bender's monthly publication. I have written many law journal articles that address royalty issues, including *Developments in Non-Regulatory Oil and Gas Law*, 32nd OIL AND GAS INST. 117 (Matthew Bender 1981); *Developments in Non-Regulatory Oil and Gas Law: The Issues of the Eighties,* 35th OIL & GAS INST. 1 (Matthew Bender 1984); *Current Lease and Royalty Problems in the Gas Industry*, 23 TULSA L.J. 547 (1988); *Defining the Royalty Obligation*, 49 SMU L.J. 223 (1996); and *Royalty Calculation in Texas*, 50th OIL AND GAS INST. Appendix Ch. 3 (Matthew Bender1999).

I am familiar with and understand the development of the law and custom and usage relating to royalties. I also have an opinion of the common understanding of those principles by people in the oil and gas industry, based on thousands of conversations with landmen, lease administrators, division order analysts, and lawyers for oil companies and royalty owners.

I have been solicited by the American Petroleum Institute to comment upon the Proposed Rules published by the Minerals Management Service at 64 Fed.Reg.73820 (December 30, 1999) in light of the history and nature of the royalty bargain. The opinions that I express are my own and not necessarily those of Southern Methodist University or the Hutchison Endowment. My opinions are based upon my 30 years experience in the oil and gas industry as a lawyer and a law professor, as well as the sources that I reference.

B. A Short History of Royalty

The economic function of a royalty is to hedge against uncertainty. When parties can determine with certainty the quantity and value of things that they wish to buy or sell, they probably will fix a lump sum or a unit price. In the case of oil and gas, however, the existence of the substance – let alone the quantity, quality and price – is uncertain. Common practice in the oil and gas industry, as well as other extractive industries, therefore, is that a major part of the compensation of leasing mineral owners is in the form of a *royalty* – a portion of production or its value that is delivered or paid free of the costs of production as oil or gas is produced. If production is prolific, the royalty owner benefits and the lessee is burdened more than if production is slight.

The term "royalty" derives from the feudal system in England, where the term was developed to distinguish the share of production reserved by the Crown from the production rights of those granted the right to work mines and quarries to develop minerals owned by the Crown. *See Taylor v. Peck*, 116 N.E.2d 417, 418 (Ohio 1953); *See also* SAMUEL H. GLASSMIRE, LAW OF OIL AND GAS LEASES AND ROYALTIES § 10, at 55 -56 (1935); HARRIET S. DAGGETT, MINERAL RIGHTS IN LOUISIANA 247 (1949). "Royalty" was also used in feudal England in the context of landlord/tenant relations. Feudal lords received title to land directly from the Crown on the condition that they would render future services. The lords in turn permitted their tenants to cultivate the land in return for a share of the products of the tenants' efforts. Feudal tenants held only a "working interest" in land, producing crops at their own labor and expense. The share of the products given to landlords by tenants was termed "royalty" since it was the portion accruing to the landowners as a result of the royal grant or favor.

The modern oil and gas lease, which conveys the right to develop minerals and provides for a concomitant royalty to the mineral owner, evolved over the years from forms used to brine water (from which salt was extracted), which in turn developed from solid minerals mining leases. *See generally* Lesley Moses, *The Evolution and Development of the Oil and Gas Lease*, 2 OIL & GAS INST. 1 (1951).

1. Royalty is due "at the well," not on downstream entrepreneurship

Historically, the royalty bargain has been that the royalty owner receives a fractional part of the production or production revenues "at the well," where the product from which the royalty is paid comes into being. Royalty has excluded value added by the lessee's entrepreneurship activities "downstream" – away from the lease.

The practice has a long history. In the Middle Ages, when the Crown enfeoffed feudal lords, the King retained a "royalty" right to take gold or silver that might be found in the lands he had conveyed. When the King alienated the right to mine, he typically reserved part of all the ore to be delivered "on top of the ground free of charge," which was also called "royalty." A.J. THUSS, JR., TEXAS OIL AND GAS § 117 at 156 (2d ed. 1935). When King Charles II granted the colony of Pennsylvania to William Penn in 1681, the royal patent reserved "one-fifth of all the gold and silver discovered in the region." SAMUEL H. GLASSMIRE, LAW OF OIL AND GAS LEASES AND ROYALTIES § 10, at 55 -56 (1935). The civil law embodied a similar concept. Spanish law recognized the *dominio radical* – literally the King's "root ownership"of minerals contained in the soil of the lands of his subjects. The right derived from the Mining Ordinance of 1783, which listed royal minerals, set out a procedure by which subjects could produce them, and authorized a royalty to the King called the *derecho del quinto* ("the tax of the fifth part"). WALACE HAWKINS, EL SAL DEL REY 9 (1947).

In the United States, royalty clauses in private-lands oil and gas leases have used terms like "market value," "amount realized," and "market price" to describe a royalty at the production point, before the lessee has applied its entrepreneurship to enhance value by transporting, processing or marketing. *See, e.g.*, CURTIS M. OAKES, BENOIT'S OIL AND GAS FORMS 7 (2d ed. 1939) ("To pay lessor . . . the equal one-eighth (1/8) of the gross proceeds at the prevailing market rate"), *quoting* Producers' 88 Standard Lease Form; SAMUEL H. GLASSMIRE, LAW OF OIL AND GAS LEASES AND ROYALTIES § 10, at 28 (1935) ("one-eighth of the gross proceeds of the gas at the prevailing market rate"); RICHARD L. BENOIT, CYCLOPEDIA OF OIL AND GAS FORMS 171 (1926) ("one-eighth of the net proceeds, based on the market or selling price at the well"). *See also* Wall v. United Gas Pub. Serv. Co., 152 So. 561, 562 (La. 1934) ("one-eighth (1/8) of the value of such gas calculated at the market price per thousand feet"); George Siefkin, *Rights of Lessor and Lessee with Respect to Sale of Gas and as to Gas Royalty Provisions*, 4 OIL & GAS INST. 181, 214 (1953) ("the equal one-eighth (1/8) of the *gross proceeds at the prevailing market rate*, for gas used off the premises") (emphasis in original), discussing the royalty clause in a typical Kansas lease.

American courts frequently have recognized directly that a lessee is entitled to entrepreneurial uses of production without sharing benefits with the royalty owner. In *Wilkins v. Nelson*, 99 So. 607 (La. 1924), the Louisiana Supreme Court denied a royalty owner's claim to a share of gasoline revenues where gasoline was extracted from a well producing only gas and the lease provided for a flat rental for gas. In *Phillips Petroleum Co. v. Record*, 146 F.2d 485 (5th Cir. 1944), and *Phillips Petroleum Co. v. Ochsner,* 146 F.2d 138 (5th Cir. 1944), the Fifth Circuit held that "market value at the well" royalty was based on the value of the gas at the well despite the fact that the lessee actually exchanged the gas produced with another who used the gas to generate heat and light, uses that commanded a higher price but which had no established market at the well. The court noted that the "Lessee . . . received the gas as owner under its lease, and it was obligated to pay appellee the market value at the well, no more and no less, and this without regard to the use made of it. *Id.* at 141. In *Sowell v. Natural Gas Pipeline Co. of America*, 789 F.2d 1151 5th Cir. 1986), the court held that gas royalties based on the average market price being paid for gas in a six-county area were paid for all of the constituents of that gas, including gas liquids collected in "drip pots" between the wellhead, the metering station and the processing plant. The court reasoned that, because production triggered the obligation to pay royalty, the rights and obligations of the parties should be assessed at the wellhead. *Carter v. Exxon Corp.*, 842 S.W.2d 393 (Tex. App.-- Eastland 1992, writ denied), held that a lease calling for royalty based upon "market value at the well" did not permit the royalty owner to share in revenues generated by the lessee in manufacturing liquid products downstream from the well because "at the well" required royalty to be determined on "gas that is produced in its natural state, not on the components of the gas that are later extracted." *Id* at 397.

Case law recognizes that royalty is due at the well, rather than downstream, even when the lease does not stipulate that the calculation is "at the well." *Wall v. United Gas Public Service Co.*, 152 So. 561 (La. 1934), is the classic case. In *Wall* the relevant lease royalty clause provided that when gas was sold or used off the premises, "the grantor shall be paid one-eighth (1/8) of the value of such gas calculated at the market price . . . ." *Id.* at 562. Gas from the well was transported about two miles and sold, along with gasoline extracted from the gas stream, for 5.8 cents per MCF. The lessees paid royalty based upon the market price of the gas at the well, approximately four cents per MCF. The lessors sued, contending that royalty should be based upon the price for which the gas was sold off the lease after transportation. The Louisiana Supreme Court ruled in favor of the lessee, reasoning that "the parties intended that, if there was a market for gas in the field, the current market price there should be paid. There is where the gas was reduced to possession and there is where ownership of it sprang into existence." *Id.* at 563. The royalty obligation does not extend to downstream entrepreneurial functions of the lessee. *See also Sartor v. United Carbon Co.*, 163 So. 103 (La. 1935); *Sowell v. Natural Gas Pipeline Co. of Am.*, 789 F.2d 1151 (5th Cir. 1986); *Phillips Petroleum Co. v. Record*, 146 F.2d 485 (5th Cir. 1944); *Phillips Petroleum Co. v. Ochsner*, 146 F.2d 138 (5th Cir. 1944); *Danciger Oil & Ref., Inc. v. Hamill Drilling Co.*, 141 Tex. 153, 171 S.W.2d 321 (1943); *Scott Paper Co. v. Taslog, Inc.*, 638 F.2d 790 (5th Cir. 1981); and the discussion at George Siefkin, *Rights of Lessor and Lessee with Respect to Sale of Gas and as to Gas Royalty Provisions*, 4 OIL & GAS INST. 181, 191-203 (1953).

Finally, the rationale of the cases recognizing that royalty is subject to post-production costs also indirectly supports a bargain that excludes entrepreneurship proceeds from the royalty obligation. It is axiomatic that the working interest must bear all of the costs of producing oil or gas; royalty is free of costs incurred "at the well" because those costs are required to create the production from which the royalty share comes. It is equally clear, however, as I will discuss below, that where royalty is valued by working back from downstream sales, costs incurred by the working interest to move or improve the product must be deducted from the downstream sales price to adjust that price "at the well." The net effect is that no royalty is due on revenues generated by a lessee's downstream or entrepreneurial activities.

Other commentators have also concluded that production activity is distinguishable from value-enhancing activities such as gathering, processing and marketing in defining the royalty obligation. *See, e.g.*, Richard C. Maxwell, *Oil and Gas Royalties — A Percentage of What?*, 34 ROCKY MTN. MIN. L. INST. 15 -1, §15.03 (1988); Richard J. Pierce, Jr., *Lessor/Lessee Relations in a Turbulent Gas Market*, 38 OIL & GAS INST. 8 -1, § 8.03[2] (1987); David E. Pierce, *Royalty Calculation in a Restructured Gas Market*, 13 E. MIN. L. INST. 18 -1, § 18.03 (1992).

2. Determining "Value"

What if there is no market at the lease? How, then, is "value" to be determined? The courts take a pragmatic approach: "Market value is a question of fact. . . . [T]he point is to determine the price a reasonable buyer would have paid . . . at the well when produced." *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 238-239 (5th Cir.1984). *See also Montana Ry. Co. v. Warren*, 137 U.S. 348 (1890). Actual sales at the wellhead at the time of production are the best evidence of value. In the absence of the producer's breach of an implied covenant to market or the existence of circumstances that distort the economics of the transaction, an actual arms-length sale at the wellhead establishes market value. *Cabot Corp. v. Brown*, 754 S.W.2d 104 (Tex. 1987); *Shamrock Oil & Gas Corp. v. Coffee*, 140 F.2d 409 (5th Cir.), *cert. denied*, 323 U.S. 737 (1944). Sales comparable in time, quantity, quality, and availability to market are the favored proof of value where there are no sales at the wellhead. *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 386-387 (10th Cir. 1975), *cert. denied*, 434 U.S. 968 (1977); *accord Phillips Petroleum Co. v. Ochsner*, 146 F.2d 138 (5th Cir. 1944). "The absence of an available market does not mean that the [product] lacks value, however." *Scott Paper Co. v. Taslog, Inc.*, 638 F.2d 790, 799 (5th Cir. 1981). Where there are neither actual sales nor comparable sales in the area of the well, the courts use a "work-back" or "net-back" method of royalty valuation, establishing value at the wellhead by deducting costs incurred by the working interest from the downstream sales price to "work back" to value at the wellhead. *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 463 F. Supp. 619, 620 (N.D. Okla. 1978), *aff'd in part, rev'd in part*, 607 F.2d 335 (10th Cir. 1979), *cert. denied*, 446 U.S. 936 (1980). "A starting place for the work-back method can be any point in the production-processing-sale chain where a dollar figure can be established by reliable evidence . . . ." *Ashland Oil Co.*, 607 F.2d at 336; *see also Ashland Oil*, 554 F.2d at 387.

The hierarchy of royalty valuation methods is entirely logical. Market value is what a willing buyer and willing seller would agree upon under the circumstances. *Ashland Oil*, *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 463 F. Supp. 619, 626 (N.D. Okla. 1978), *aff'd in part, rev'd in part*, 607 F.2d 335 (10th Cir. 1979), *cert. denied*, 446 U.S. 936 (1980); State v. Carpenter, 126 Tex. 604, 89 S.W.2d 979 (1936); Exxon Corp. v. Jefferson Land Co., 573 S.W.2d 829, 830

(Tex. Civ. App. — Beaumont 1978, writ ref'd n.r.e.). Where gas is actually sold at the wellhead in a transaction negotiated at the time of sale, all elements of the definition and the transaction are in congruity unless the sale is not at arms length or the parties act unreasonably; thus, an actual sale at the wellhead is the best evidence of value. Comparable sales illustrate an available market and are strong evidence of value where there are no actual sales. The circumstances of comparable sales, however, will never be completely the same as the circumstances at the wellhead. *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 386 (10th Cir. 1975), *cert. denied*, 434 U.S. 968 (1977) (rejecting a determination of value based on data covering "a broad time span and a wide geographical distribution, [because] [t]he transactions . . . were too remote in time or place."). The work-back method "is the least desirable method of determining market price`" because it begins furthest from the wellhead so that there are likely to be more variables to consider. *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 239 (5th Cir.1984), (quoting *Montana Power Co. v. Kravik*, 586 P.2d 298, 303-304 (Mont. 1978). But the work-back method "can be just as accurate as any other method . . ." though "it is more difficult to apply." *Ashland Oil,* 554 F.2d at 387; *see also Piney Woods*, 726 F.2d at 240.

Until the Proposed Rule, federal practice and law has been consistent with this analysis, requiring a lessee to pay royalty on the value of production at the lease and looking first to establish value in the lease area. The Mineral Lands Leasing Act, 30 U.S.C. § 226(b)(1)(A), provides for royalty "in amount or value of the production removed or sold from the lease." The Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1335(a)(8), 1337(a) and 1337(b)(3), requires that the lessee pay royalty "in amount or value of the production saved, removed, or sold" from leased premises. Courts have interpreted these statutory provisions to mean that royalty should be based on the value of production at the lease. For example, *United States v. General Petroleum Corp.*, 73 F. Supp. 225 (S.D.Cal.1946), held that "value of production" under the Mineral Lands Leasing Act refers to value of oil and gas at the wellhead. *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), *cert denied*, 480 U.S. 940 (1987), upheld a net-back accounting methodology and allowed the lessee to deduct both transportation and marketing costs.   Indeed, the MMS' itself has recognized that federal royalty is based upon value of production at the lease, free of cost, rather than in an enhanced value attributable to downstream activities. *See Petro-Lewis Corp.*, 108 IBLA 20 (1989) (appropriate royalty must reflect market price at the lease); *See also* Notice of Proposed Rulemaking, 52 Fed. Reg. 30776, 30797 (August 17, 1987) (royalty values must be "adjusted for transportation and/or processing to determine value at the lease").

Thus, to the extent that the Proposed Rule would establish as a norm that federal lessees should pay royalty based upon downstream prices – whether spot, futures or transactions – it goes beyond the history and logic of royalty. History and logic suggest that the royalty obligation is limited to the fruits of lessees' production activities.[1]

C. The Treatment of "Downstream" Costs

The black letter law relating to costs incurred beyond the lease is clear and consistent with the general concept of royalty. The lessee must bear all of the *costs of production*; royalty is free of the costs of production because those costs are required to create the product from which the royalty share comes. Where royalty is valued at the well based upon downstream sales, costs incurred by the working interest to move the product or to improve its quality – *costs subsequent to production* – must be deducted from the downstream sales price. For discussion, see 3 HOWARD R. WILLIAMS, OIL AND GAS LAW §§ 645-645.3 (Matthew Bender 1998); 3 EUGENE O. KUNTZ, THE LAW OF OIL AND GAS §§ 39.4, 40.5 (1989); 2 W.L. SUMMERS, OIL AND GAS § 400 (Permanent ed. 1958).

Again, the rationale of the fundamental principle is based upon economic and equitable logic. The value of any commodity depends upon its proximity to market, and the value of oil or gas normally increases as it is moved closer to the burnertip. Thus, costs subsequent to production tend to increase the value of the product and must be deducted from the downstream sales price to obtain an accurate valuation "at the well." As the Fifth Circuit has said:

> [I]n determining market value costs which are essential to make a commodity worth *anything* or worth *more* must be borne proportionately by those who benefit. To put it another way: in the analytical process of reconstructing a market value where none otherwise exists with sufficient definiteness, all increase in the ultimate sales value attributable to the expenses incurred in transporting and processing the commodity must be deducted. The royalty owner shares only in what is left over, whether stated in terms of cash or an end product.

Freeland v. Sun Oil Co., 277 F.2d 154, 159 (5th Cir.1960) (Italics in original). *See also Piney Woods Country Life School v. Shell Oil Co.*, 539 F.Supp. 957, 971 (S.D.Miss.1982); *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir.1984).

The rationale is sometimes stated in equitable terms. Since oil or gas usually becomes more valuable as it is moved closer to the place it is used, it would be unfair to the lessee to calculate royalty on the downstream sales price without fully deducting the costs incurred in

[1] Though I hesitate to list it as support, my colloquial experience of nearly 30 years dealing with lessors and lessees also supports the distinction between the production function and downstream entrepreneurship that may (or may not) enhance value. In my experience, lessors do not generally expect to share in the benefits (or the risks) of the lessee's entrepreneurship.

moving the product and improving its quality, because that would unjustly enrich the royalty owner, whose royalty is due at the well. *See Freeland v. Sun Oil Co.*, 277 F.2d 154, 159 (5th Cir. 1960); *Piney Woods Country Life School v. Shell Oil Co.*, 539 F.Supp. 957, 971, 973 (S.D. Miss. 1982); *Miller v. Buck Creek Oil Co.*, 38 Wyo. 505, 269 P. 43, 45 (1928); *Coyle v. Louisiana Gas & Fuel Co.*, 175 La. 990, 1009, 144 So. 737, 742 (La. 1932).

While the basic principle that royalty is subject to costs subsequent to production has been unquestioned, there is some disagreement about what specific costs fall within the "subsequent to production" class. One way to state the issue is when is "production" complete for purposes of the royalty clause?

1. "Production" is complete when oil or gas is captured

Until the latter half of the 20th Century it was generally accepted that "production" occurs for royalty valuation purposes when oil or gas is captured – at the wellhead or on the lease – so that the costs of marketing, transporting, compressing and processing beyond the lease, as well as certain severance and gross production taxes, are charged proportionately to the royalty interest. *See*, the excellent survey of the development of the law by Justice Owen in the concurring opinion in *Heritage Resources, Inc. v NationsBank*, 939 S.W.2d 118, 125-29 (Tex. 1996). The rule that "costs subsequent to production" are all costs after capture follows from the principle that royalty is due "at the well," excluding downstream increases in value due to the lessee's entrepreneurship.

Martin v. Glass, 571 F. Supp. 1406 (N.D. Tex. 1983), is a classic example of this analysis. At issue was whether compression costs could be deducted in calculating the amount due to an overriding royalty interest reserved by lessors in a situation in which the lease addendum was silent as to the place at which the royalty was due. *Id.* at 1409. The court first concluded that the overriding royalty was due "at the well" by referring back to the underlying lease, which provided for a lessors' royalty based upon the "net proceeds at the well received . . . on or off the premises." *Id.* at 1410. The court then applied a "plain meaning" test, since there was no evidence that the lease language was used in "a special or technical sense." to hold that "[c]osts incurred prior to production are to be borne by the operator, while costs subsequent to production (those necessary to render the gas marketable) are to be borne on a pro rata basis between operating and nonoperating interests." *Id.* at 1411-12. The court held that compression costs were properly charged in calculating the royalty because "[t]here existed no purchaser, or market, for the gas as it existed in the wellhead because of its low pressure. Thus, compression being required to market the gas, said charges were post-production costs and as such were properly deductible from nonoperating interests." *Id.* at 1416.

2. "Production" is complete when the lessee obtains a product in marketable condition

Professor Maurice Merrill stated a theory for a mor e expansive royalty obligation, however, in 1940, based upon the implied covenant to market: "If it is the lessee's obligation to market the product, it seems necessarily to follow that his is the task also to prepare it for market, if it is unmarketable in its present form." MAURICE H. MERRILL, COVENANTS IMPLIED IN OIL AND GAS LEASES § 85 (2d ed. 1940). Cases and commentators at first gave little support to what was called the "marketable product" or "marketable condition" doctrine. (*See, e.g.*, Richard B. Altman & Charles S. Lindberg, *Oil and Gas: Non-Operating Oil and Gas Interests' Liability for Post-Production Costs and Expenses*, 25 OKLA. L. REV. 363 (1972); George Siefkin, *Rights of Lessor and Lessee with Respect to Sale of Gas and as to Gas Royalty Provisions*, 4 OIL & GAS INST. 181, 191-203 (1953). Gradually, however, support for Professor Merrill's doctrine grew.[2] Two cases from Kansas in the 1960s and an Arkansas decision in the late 1980s – all involving gas compression charges – appeared to hold that post-capture costs incurred to make a marketable product could not be charged to royalty. *See Gilmore v. Superior Oil Co.*, 388 P.2d 602 (Kan. 1964); *Schupback v. Continental Oil Co.*, 394 P.2d 1(Kan. 1964); *Hanna Oil and Gas Co. v. Taylor*, 759 S.W.2d 563 (Ark. 1988). In 1988, the MMS adopted regulations expressly requiring that federal royalties be based on production in marketable condition. 53 *Fed. Reg.* 1184 and 1230 (January 15, 1988). Federal lessees must "place oil in marketable condition at no cost to the Federal Government. . . ." 30 C.F.R. § 206.102(i) (1993).

In the 1990s, a spate of decisions in Oklahoma, Colorado, and Kansas ruled that "production" is not complete until oil or gas has been both captured and made marketable. *See, e.g.*, *Wood v. TXO Production Corp.*, 854 P.2d 880 (Okla. 1992); *TXO Production Corp. v. State of Oklahoma ex rel. Commissioner of the Land Office*, 903 P.2d 259 (Okla. 1994); *Garman v. Conoco, Inc.*, 886 P.2d 652 (Colo. 1994); *Sternberger v. Marathon Oil Co.*, 894 P.2d 788 (Kan. 1995). While these cases are not completely consistent, their underlying premise is that a lessee has an implied duty not only to seek a market for production, but to make production marketable. By this view, "production" is not complete for royalty purposes until the lessee has put the captured product in a marketable condition. Under the marketable product rule, a lessee may charge the royalty for costs of transporting, compressing and processing *only* if the oil or gas is marketable at the well or if those costs are incurred at a point after the lessee has paid the costs of making the oil or gas marketable.

But while the states have embraced different rules about when "production" is complete, no state has questioned the fundamental principle that once "production" has been obtained, the royalty must share with the lessee subsequent costs of compressing, transporting, processing and marketing. Indeed, the leading statement of the marketable product rule, *Garman v. Conoco, Inc.*, 886 P.2d 652 (Colo. 1994), affirmed that:

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[2] A comprehensive examination of the derivation and rationale of the marketable product rule may be found at Owen L. Anderson, *ROYALTY VALUATION: SHOULD ROYALTY OBLIGATIONS BE DETERMINED INTRINSICALLY, THEORETICALLY, OR REALISTICALLY?PART 1*, 37 NAT. RES. J. 547, 604-609 (1997).

> Our answer is limited to those post-production costs required to transform raw gas into a marketable product. As we explained at the outset, many different types of expenses may be involved in the conversion process. Upon obtaining a marketable product, any additional costs incurred to enhance the value of the marketable gas, such as those costs conceded by the Garmans [processing and transportation costs incurred after a marketable product had been obtained], may be charged against nonworking interest owners.

Id. at 660. The *Garman* Court relied in part for its statement upon federal practice:

> When the federal government has considered these processes it has distinguished between "operations that condition a product for market, for which a lessee is not entitled to an allowance, and those that transform it. If transformation is involved, a manufacturing allowance is appropriate." See Exxon Corp., 98 I.D. 110, 127, 118 I.B.L.A. 221 (1991).

Id. at 660, n.26.

Professor Eugene Kuntz, whose analysis the Colorado Supreme Court weighed heavily in reaching its decision in *Garman*, and who was the chief proponent for the marketable product rule in the latter half of the 20th Century, also recognized that royalty should be subject to marketing costs after the lessee had put oil in marketable condition:

> After a marketable product has been obtained, then further costs in improving or transporting such product should be borne by both lessor and lessee.
>
> * * *
>
> [I]t may be concluded that the lessee has a duty to produce a marketable product and to bear all expenses of such production, that the lessee has a duty to market the product after it is extracted, but that *unless the lease reveals a contrary intention, the expenses incident to marketing the product should be shared by the lessor and lessee.*

3 EUGENE O. KUNTZ, THE LAW OF OIL AND GAS § 39.4(b) (1989) (Italics added).

Thus, while state law and legal logic are not in complete agreement as to when "production" is complete, there is no support in either for the proposition that lessees should be required to bear all costs of marketing.

The Summary and Discussion of the Proposed Rule recognizes that the marketing covenant and the duty to put production into marketable condition are different. 64 *Fed. Reg.* at 73824. It suggests, however, that "the creation and development of markets is the essence" of the implied covenant to market. 64 *Fed.Reg.* at 73822. I believe that those who wrote the Summary and Discussion of the Proposed Rule misunderstand the implied covenant to market. No implied covenant imposes a duty on lessees to market after “production” at no cost to the lessor.

"Because of the lessee's exclusive control over the production and development of oil and gas, the law imposes upon the lessee certain implied covenants," including an implied covenant to market within a reasonable time and at a reasonable price and an implied covenant to operate diligently and properly. *Piney Woods Country Life School v. Shell Oil Co.*, 539 F.Supp. 957, 973 (S.D. Miss. 1982); *Sauder v. Mid-Continent Pet. Corp.*, 292 U.S. 272, 279, 54 S.Ct. 671, 78 L.Ed. 1255 (1934). Generally, the leasehold interest's obligation is described as a "prudent operator" standard: the lessee must do "Whatever, in the circumstances, would be reasonably expected of operators of ordinary prudence, having regard to the interests of both lessor and lessee . . . ." *Brewster v. Lanyon Zinc Co.*, 140 Fed. 801, 814 (8th Cir. Kan. 1905), quoted with approval in *Sa uder*, 292 U.S. at 280. For discussion and references to other sources, see EUGENE O. KUNTZ, JOHN S. LOWE, OWEN L. ANDERSON, ERNEST E. SMITH AND DAVID E. PIERCE CASES AND MATERIALS ON OIL AND GAS LAW 232-236 (3d ed. West 1998).

Courts and commentators have recognized historically that the implied covenant to market may impose a duty upon a lessee to act on or near the lease to make production possible to take advantage of a market. But the covenant to market imposes no duty to act away from the lease to create a market. *See Craig v. Champlin Petroleum Co.*, 435 F.2d 933 (10th Cir. 1971). *See also* the discussion at 5 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW § 856.1 (1998); GEORGE SIEFKIN, *Rights of Lessor and Lessee with Respect to Sale of Gas and as to Gas Royalty Provisions*, 4 OIL & GAS INST. 181, 203-209 (1953). For example, while the implied covenant to market may possibly require the lessee to install a booster on the lease to force gas into a pipeline (*Swamp Branch Oil & Gas Co. v. Rice*, 70 S.W.2d 3 (Ky. 1934)) or to construct a plant to permit carbon dioxide production (*Libby v. De Baca*, 179 P.2d 263 (N.M. 1947)), the lessee has no implied obligation to construct a pipeline to permit production to be marketed. *See, e.g.*, *Kretni Dev. Co. v. Consolidated Oil Corp.*, 74 F.2d 497, 499 (10th Cir. 1934), cert. denied, 295 U.S. 750 (1935); *Ashland Oil & Ref. Co. v. Staats, Inc.*, 271 F. Supp. 571, 575 (D. Kan. 1967) and *Fey v. A.A. Oil Corp.*, 285 P.2d 578, 587 (Mont. 1955). It follows from cases such as these and from the fundamental royalty principles discussed above that the implied covenant to market does not justify imposing all marketing costs on lessees.

Indeed, where the measure of royalty is “value,” the cases have imposed no implied-covenant-to-market obligation on the lessee to seek the best price reasonably available – “value” is an objective standard, not related to the lessee’s efforts. *See, e.g.*, *Shamrock Oil & Gas Corp. v. Coffee*, 140 F.2d 409 (5th Cir.), *cert. denied*, 323 U.S. 737 (1944); *Haynes v. Southwest Natural Gas Co.*, 123 F.2d 1011 (5th Cir. 1941); *Montana Power Co. v. Kravik*, 586 P.2d 298 (Mont. 1978); *Sartor v. United Gas Public Service Co.*, 173 So. 103 (La. 1937); *Wall v. United Gas Public Service Co.*, 152 So. 561 (La. 1934); *Clear Creek Oil & Gas Co. v. Bushmiaer*, 264 S.W. 830 (Ark. 1924); *Phillips Petroleum Co. v. Ochsner*, 146 F.2d 138 (5th Cir. 1944). An implied covenant does not contradict express lease terms. *See e.g.*, *Danciger Oil & Refining Co. v. Powell*, 154 S.W.2d 632, 635 (Tex. 1941); and *Williamson v. Elf Aquitaine, Inc.*, 138 F.3d 546, 551 (5th Cir. 1998).

Moreover, nothing in the history or logic of the implied covenant to market justifies penalizing a lessee who markets away from the lease or sells in a non-arm's-length transaction by denying the full deductibility of marketing costs. A sale to a related party does not breach the implied covenant to market in and of itself. *See Garfield v. True Oil Co.*, 667 F.2d 942 (10th Cir. 1982); *Craig v. Champlin Petroleum Co.*, 435 F.2d 933 (10th Cir. 1971); *Parker v. TXO Prod. Corp.*, 716 S.W.2d 644 (Tex. App.-- Corpus Christi 1986, no writ).

Thus, to the extent that the Proposed Rule would establish as a norm that federal lessees should bear all marketing costs – even those incurred after the lessee has placed production in a marketable condition – it goes beyond the history and logic of royalty. The obligation some jurisdictions place upon lessees to put product into marketable condition does not translate to an obligation to market production free of cost to the royalty. The royalty "bargain" requires that costs "subsequent to production" be shared.

D. Conclusion

In my opinion, the Proposed Rules would impose a duty upon oil producers far beyond the bargain of the royalty obligation at American common law and far beyond the expectations of persons familiar with oil and gas leases. A fundamental principle is that royalty is due "at the well," not on the lessee's downstream entrepreneurial activities. Where no market exists in the area, "value" may be determined by netting back from a downstream sale, though that is the "least desirable method" of establishing value because of the risk of distortion. But history, case law and logic require that post-production costs – such as marketing – be deducted in reaching "value" by a net-back methodology. Some states extend the lessee's duty by holding that "production" is not complete until the lessee obtains a marketable product, so that the lessee must pay all costs of capturing and of placing the product in a marketable condition. There is simply no support, however, for imposing an obligation upon the lessee to pay costs of marketing after a product exists in a marketable condition.

Appendix D

"A Recommended Rate of Return Methodology for Calculation of Transportation Allowances in Non-Arm's Length Crude Transportation Arrangements," by Elizabeth H, Crowe and Carl V. Swanson, Swanson Energy Group.

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICE

Establishing Oil Value for Royalty Due on	)	30 CFR Part 206
Federal Leases; Proposed Rule	)	64 FR 73820
		(December 30, 1999)

A Recommended Rate of Return Methodology
for Calculation of Transportation Allowances
in Non-Arm's Length Crude Oil Transportation Arrangements

Prepared for:

the American Petroleum Institute
the Domestic Petroleum Council
the Independent Petroleum Association of America
the United States Oil and Gas Association

January 2000

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Mineral Management Service 30 CFR Part 206
Establishing Oil Value for Royalty Due on Federal Leases
64 DE 73820 (December 30, 1999)

Determining Rate of Return Applicable to Transportation Systems

I. Executive Summary

As part of its proposed 30 CFR Part 206 rulemaking regarding oil royalty valuation, the MMS has requested comments regarding the determination of an appropriate rate of return to be reflected in the transportation allowance under non-arm's-length arrangements for movement of oil produced from Federal lands to a point of sale off the lease. Based on a review of current publically available data concerning capital structure and cost of capital for companies engaged in upstream oil production activities, as well as the practices of other regulatory agencies which set cost-based rates for public utilities, this report recommends that the MMS adopt a composite industry cost of capital equal to two times the Standard & Poor's BBB industrial bond rate.

As discussed in more detail in the body of this report, current data suggest that a capital structure of 30% debt and 70% equity would be a conservative measure of a median ratio for the producing industry, particularly given the fact that equity ratios for integrated oil companies are generally higher than 70%. Moreover, this ratio accurately reflects the risks associated with upstream pipelines and other investments in oil and gas assets. The industry composite range for the cost of equity capital of oil and gas companies in 1998 - 1999, as estimated by independent analysts using either a capital asset pricing method (CAPM) or a discounted cash flow (DCF) method, is 7.10% to 17.30%. Using 13% for equity capital and the 1999 S&P BBB yield of 7.4%, combined with a 30/70 debt/equity capital structure, produces an 11.3% after-tax weighted average cost of capital (WACC). Given the fact that oil pipelines are typically financed by parent companies using both debt and equity, and income tax expense will be incurred on the portion of the return associated with the equity investment, it is necessary to calculate the cost of capital reflected in the transportation allowance computed by the MMS on a pretax basis. Given a 35% federal income tax rate, the weighted pretax cost of capital is 16.2%, or 2.2 times the BBB rate.

These results lead us to conclude that a cost of capital of 2 times the BBB bond rate is a reasonable reflection of the actual capital costs incurred by domestic oil transporters, particularly the offshore oil pipelines to which the MMS transportation allowance will largely pertain. The data and reasoning on which this conclusion is based are presented more fully in Section II.

Section II

A. Whether to Include an Equity Component in the Rate of Return

The Swanson Energy Group, Inc. has been asked by a group of oil associations and companies, which is filing joint comments in the instant proceeding, to evaluate the MMS policy concerning the rate of return allowance included in non-arm's length transportation allowance determinations in light of the MMS recent request for comments, and to make recommendations concerning a reasonable cost-based methodology for the MMS to adopt. Our firm's qualifications and experience are appended to this report as Attachment A.

Under current MMS regulations governing the valuation of oil for royalty purposes, the transportation allowance permitted for non-arms length arrangements includes a return on capital investment which is calculated using Standard and Poor's BBB bond rate as the rate of return.[1] The basis for this policy, as articulated by the MMS in its December 30, 1999 further supplementary proposed rule (December 1999 proposal), is to attempt to base the transportation allowance on "actual costs incurred to transport the oil."[2] Thus, the MMS is implicitly assuming that the actual cost of money for building a pipeline to move oil from federal leases to the point of sale is essentially the rate at which money can be borrowed by companies in the oil pipeline business, as represented by the industrial BBB corporate bond rate.

The difficulty with this assumption is that pipelines are rarely, if ever, financed entirely by debt. It is highly unlikely that a lender would agree to undertake the entire cost of building a pipeline, given the high risk of default such a situation would create. It is more likely that oil pipelines, especially the offshore pipelines which transport oil from federal leases, will be financed by entities which own, directly or indirectly, economic interests in production from the leases to be served by the pipeline. Less frequently, such pipelines may be financed by entities which do not own such economic interests. In either case, most or all of the capital investment in the transportation facility will be funded by equity rather than debt.

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[1] 30 CFR Part 206 §157(b)(2)(iv) and (v).

[2] See December 1999 proposal at p. 73835.

If it is true that transportation facilities are built with at least some equity capital rather than 100% debt capital, the question arises as to whether the cost of that equity capital should be reflected in the MMS transportation allowance at some rate other than the BBB bond rate. The cost of equity capital, while not directly observable in financial markets in the same manner as the cost of debt, is higher than the cost of debt capital. While there are different approaches used by investment firms and regulatory agencies to estimate the cost of equity capital for any given industry or company, the data consistently suggest that investors expect a higher rate of return on their equity investment capital than they do on debt capital. Table 1 presents calculations by several investment firms and financial experts of the recent cost of equity capital computed for various segments of the petroleum industry. As shown on that table, different firms and different methods produce a range for selected oil and gas companies of 7.10% to 17.30% for the cost of equity capital in late 1998 and early 1999. The comparable Moody's Baa corporate bond rate for March 1999 was 7.53%.[3] To the extent that equity capital is used to build oil pipelines from federal lease locations, then the cost of that capital is an actual cost of the pipeline, and the return allowance computed by the MMS should reflect that cost.

Three questions arise from this conclusion. First, what cost of equity capital should be reflected? Second, should that equity cost be calculated on a before-tax or after-tax basis? Third, how should the relative portions of debt and equity capital be determined? These questions are addressed in turn below.

B. How to Calculate the Cost of Equity Capital

As mentioned above, there are several different accepted methods for calculating investors' expected return on equity capital for a company or industry. The data in Table 1 reflects both the CAPM and DCF (or dividend growth) methods. It is our judgment that the average of the equity costs calculated by Ibbotson Associates for the oil and gas extraction industry (SIC 13) is a reasonable, and perhaps low, measure of current investor expectations for

[3] Moody's Baa bond rate is comparable to Standard & Poor's BBB bond rate and is publically available. March 1999 is used because Ibbotson's CAPM equity costs calculations are based on March 1999 yields for treasury bond (risk-free) rates.

equity return on a project such as the transportation facilities used to move oil from federal leases. Ibbotson is a recognized authority in the compilation and interpretation of financial data, and their studies include the largest number of companies of any source we reviewed. In addition, the 13% composite SIC 13 industry average of the four methods used to calculate cost of equity capital by Ibbotson is in the middle of the range of equity capital costs produced for comparable industry segments by all sources we reviewed, as shown on Table 1.

As a point of reference, a 13% cost of equity capital for 1999 is lower than the range calculated by the Federal Energy Regulatory Commission (FERC) for an oil pipeline in its most recent determination of cost-based rates for an oil pipeline.[4] In a decision issued in January 1999, the FERC determined that the appropriate range for SFPP's cost of equity capital was 12.74% to 14.39%, and that SFPP's risk warranted a 14.27% rate of return on equity capital.[5]

C. Whether to Use a Before-Tax or After-Tax Cost of Equity

Income taxes are a part of any viable economic entity's cost of doing business. Income taxes are costs incurred by oil and gas pipelines in providing transportation, whether that service is provided for affiliated or non-affiliated shippers. As such, they should be included and reflected in any definition or calculation of the "actual" costs of providing transportation service. To our knowledge, all energy regulatory agencies involved in setting or approving rates for oil and gas transporters allow both an equity return and related income tax component to be included in cost-based rates, in recognition of the fact that these represent normal ongoing costs of providing service which should be included in customers' rates in a just and reasonable amount. For most regulatory authorities, this amount is determined by calculating the actual federal and state income taxes which would be paid by the utility if the taxable income were equal to the allowed return on equity included in the approved cost of service.

If the MMS does not wish to recognize incomes taxes as a separate line item in the

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[4] *SFPP, L.P.*, 86 FERC ¶ 61,022, Opinion No. 435 (1999).

[5] See p. 61,102; this range reflects equal weighting of short and long-term growth factors, and should be higher to reflect current FERC policy of 2/3 weighting for the short-term growth factor and 1/3 weighting for the long-term factor.

calculation of a transportation allowance, then it follows that the rate of return itself should be adjusted to reflect a before-tax return on equity capital. The simplest way to do this is to "gross up" the allowed rate of return on equity to include the applicable income taxes. Because most of the pipelines to which the transportation allowance will be applied are located in federal offshore waters, we suggest for simplicity purposes that the federal income tax rate be included, but any potential state income taxes be ignored. The 13% rate of return on equity we discuss and recommend above is a nominal, after-tax rate. That is, it is the equity investors' expected rate of return after corporate income taxes have been paid. A grossed-up after-tax rate of return on equity of 13% would equate to a pre-tax rate of return on equity of 20%.[6]

D. What is the Appropriate Capital Structure to Use

The before-tax cost of equity capital is part of a pipeline's actual costs. The next issue is to determine capital structure, that is, the relative share of debt and equity financing in any given pipeline's capitalization. While it would be at least theoretically possible to determine an actual capital structure for each individual facility for which a transportation allowance must be calculated, this approach would be both burdensome and problematic. The difficulties which would arise include the fact that the capital structure of the ultimate parent company of each individual transportation system will often reflect wide-ranging and diverse interests and business activities not necessarily directly related to the oil transportation industry segment for which a cost is being calculated. In addition, such an effort would result in widely diverging debt and equity ratios among transporters, which would produce a wide range in actual costs, even for very similar services.

Given the fact that the data for most integrated oil companies indicate a fairly narrow range of debt to total capital ratios, we recommend that the MMS adopt a standard capital

[6] Calculated by dividing the equity rate of return by (1-t). This provides an adjusted (before-tax) return equivalent to that used by the FERC and other regulatory agencies, which deduct interest expenses from return to calculate an after-tax return on equity. By grossing-up the equity return, income is provided to cover both the income taxes and the normal return on the investment of equity holders. A similar adjustment made for taxes on income used to cover payments to bondholders is offset by the fact that these interest payments are a deductible cost. Hence, the reported return on debt instruments (here, the return on BBB bonds) is the appropriate measure of the firm's cost of debt.

structure to apply in the calculation of all transportation allowances for non-arm's-length arrangements. As shown on Table 2, the debt ratios for the bulk of the companies included in the reported data range from 25% to 34%. A 30% debt ratio is consistent with both Ibbotson's report on current debt ratios for SIC 13 and 131, and the average of the EIA's current and 5-year average debt ratios for the Financial Reporting System (FRS) companies.[7] Thus, we recommend using a 30% debt and 70% equity structure for calculating the rate of return applicable to the transportation allowance.

III. Conclusion

Based on the information and discussion presented above, we calculate a current pretax weighted cost of capital of 16.2%. This reflects a 30% debt and 70% capital structure, a 20% before-tax rate of return on equity, the 1999 BBB bond rate of 7.4% for debt capital, and a 35% federal income tax rate.[8]The weighted after-tax cost of capital would be: (0.074)*(0.3) + (0.13)*(0.7) = 0.1132 Because this rate of return is just over 2 times the BBB bond rate, we recommend that for ease of administration the MMS adopt a rate of return for calculation of the actual cost of transportation under non-arm's-length arrangements of 2x BBB.

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[7] The FRS companies are 24 major U.S. energy companies which derive the bulk of their revenues and income from petroleum operations.

[8] Calculation of pretax weighted cost of capital: (0.074)*(0.3) + (0.20)*(0.7) = 0.1622

CARL V. SWANSON

Dr. Swanson is President of the Swanson Energy Group, Inc., an independent consulting firm offering management and economic counsel to the energy industry and energy consumers. Dr. Swanson has been a consultant to industry and government for 35 years. He has advised managers in the energy industries on investment, acquisition, market planning, and business strategy decisions. In providing this advice he has forecasted the supply, demand and price of various forms of energy, analyzed markets in detail, interpreted governmental views, evaluated the impact of changes in the business environment, and defined the competitive position of various suppliers. He has counseled on future supply trends, risks, pricing, and contract terms. He has also helped clients to implement recommendations with training programs, new organizations, and computer-based management tools.

Dr. Swanson has presented expert testimony before legislative, judicial, arbitral, and regulatory bodies on utility rates, energy economics, markets, fuel supply, market power, demand, curtailments, prices and appropriate discount rates. Much of this expert testimony has been before the U.S. Federal Energy Regulatory Commission (FERC) on rates, regulatory restructuring and market power. He has also testified before the Legislature of California and the California Public Utilities Commission on electricity rates and rate policy, as well as the U.S. House of Representatives Subcommittee on Energy and Power.

Dr. Swanson has given numerous speeches about the energy industry. His published articles include: *Economics of Regulation Call Attention to Rates, Unbundling, Supply* with Elizabeth H. Crowe, Natural Gas, January 2000*; Serious Pipeline Issues in 1999*, Natural Gas, January 1999; *Gas Prices in 1996*, Natural Gas, January 1996; *Drilling Results: Better but Not Great* with Michael Lynch, Natural Gas, November 1993; *What Sets the Price of Natural Gas?*, Natural Gas, November 1985; and *Strategic Changes in Pipeline Rates and Contracts: Response to Market Pricing in the Natural Gas Industry*, Oil and Gas Analyst, March 1984.

Prior to founding the Swanson Energy Group, Inc., Dr. Swanson was Executive Vice President and co-founder of Jensen Associates, Inc., an energy economics consulting firm. For five years, Dr. Swanson was on the faculty of M.I.T.'s Sloan School of Management where his teaching and research focused upon the practical use of computer information systems and models to improve management decision-making. While at M.I.T., he consulted with Arthur D. Little, Inc., the RAND Corporation, the MITRE Corporation, the U.S. Army, and the Institute Nationale de la Recherche Agronomique in Paris. He is a member of the Boston Economic Club and the International Association for Energy Economics. He received the degrees of Bachelor of Science in Economics and Electrical Engineering from the Massachusetts Institute of Technology, and Doctor of Philosophy in Management, with emphasis upon Economics and Finance, from M.I.T.'s Sloan School of Management.

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Regulatory Analysis and Expert Testimony

- Testimony at the FERC in pipeline rate cases concerning cost of service, cost classification, cost allocation, rate design and throughput level.
- Preparation of cost of service, rates and financial schedules for pipeline certificate applications.
- Development of an incentivized cost-based ratemaking proposal for gas pipelines.
- Analysis and recommendations in FERC proposed rulemakings to revise Uniform System of Accounts and pipeline filing requirements.
- Analysis of competition on pipeline applying to participate in FERC's capacity release pilot program.
- Feasibility analysis of FERC's proposed negotiated services policy for natural gas pipelines.

Supply, Demand and Price Analysis

- Analysis of the competitive positions of specific natural gas pipelines through development of average cost profiles.
- Quantitative analysis of the vulnerability of a producer's sales to specific pipeline companies due to the impact of FERC Order Nos. 380 and 436.
- For a major transmission company, profiles of direct and indirect sales and end-use markets to assist in the determination of market prospects.
- Development of various databases for monitoring supplies, deliveries, prices and other developments and trends in the U.S. natural gas industry.

Prior to working for the Swanson Energy Group, Inc., Ms. Crowe held a staff position with a non-profit organization providing support services for undergraduate student groups. Other work experience includes accounting and financial analysis for a corporation in the biomedical industry. Ms. Crowe received a Bachelor of Arts in Economics, magna cum laude, from Wellesley College.

Table 1

Cost of Equity Capital for Oil and Gas Companies
1999

Source	Industry	SIC	No. of Firms	Levered Beta Coefficient	Equity Market Risk Premium	CAPM Adj. OLS	CAPM + sm. prem.	Discounted Cash Flow 1-Stage	Discounted Cash Flow 3-Stage	*Average*
						Cost of Equity Capital (Percent)				
(a)	Oil and Gas Extraction	13	130	0.92	7.50	13.25	14.38	17.30	7.10	*13.01*
	Crude Petroleum and Natural Gas	131	101	0.83	7.50	11.91	13.51	16.19	13.30	*13.73*
(b)	Petroleum (Integrated)		41	0.90	5.50	10.22				*10.22*
	Petroleum (Producing)		104	0.90	5.50	10.27				*10.27*
								Low	High	
(c)	Petroleum Pipelines		4					13.11	14.58	*13.85*
(d)	Petroleum Pipelines		6					12.74	14.85	*13.80*
(a)	All mid-sized companies		582		7.50	13.43	13.92	16.85	13.10	*14.33*

Sources:

(a) Ibbotson Associates, Cost of Capital Quarterly, 1999 Yearbook; industry composite for SIC 13; median for SIC 131
CAPM Adj. OLS is adjusted ordinary least squares method; CAPM + sm. premium includes premium added for small and medium-sized companies.
Risk-free asset is long-term government bond; yield for March 31, 1999 (5.91%)

(b) NYU Stern Business School, Cost of Capital by Industry, December 31, 1998

(c) J. Peter Williamson, Laurence F. Whittemore Professor of Finance, Emeritus, Amos Tuck School of Business Administration
Two-stage DCF model which reflects FERC policy on equity capital: dividend yields for each firm are adjusted for compounding;
adjusted yields and the weighted growth factor are then added to calculate a cost of equity for each firm); dividend yields are for April to September, 1999.

(d) FERC range of equity returns approved in SFPP rate proceeding (Docket No. OR92-8, et. al.); reflects equal weighting of short and long-term growth rather tha

1/ Companies from all industries with equity capitalization > $0.9 billion and < $4.2 bi

Table 2

Capitalization Ratios for Oil and Gas Companies
1997 - 1999

Source	Industry	SIC	No. of Firms	Debt / Total Capital Latest	Debt / Total Capital 5-yr avg.
(a)	Oil and Gas Extraction	13	130	30.19%	23.39%
	Crude Petroleum and Natural Gas	131	101	32.56%	25.77%
(b)	Petroleum (Integrated)		41	12.72%	
	Petroleum (Producing)		104	33.84%	
(c)	Petroleum (Integrated)		26	24.54%	24.45%
	Petroleum (Producing)		12	52.72%	47.97%
(d)	Financial Reporting System Cos		24	28.00%	32.07%
(a)	All mid-sized companies	1/	582	28.93%	30.24%

Sources:

(a) Ibbotson Associates, Cost of Capital Quarterly, 1999 Yearbook; industry compo
(b) NYU Stern Business School, Cost of Capital by Industry, December 31, 1998
(c) Value Line (1998; 4-year average 1995-1998)
(d) EIA, Performance Profiles of Major Energy Producers, 1997, Table B4

Notes:

1/ Companies from all industries with equity capitalization > $0.9 billion and < $4.2

Appendix E

"Pricing Royalty Crude Oil," by Samuel A. Van Vactor, President, Economic Insight, Inc.

Pricing Royalty Crude Oil

Samuel A. Van Vactor

January 29, 2000 ***Economic Insight, Inc.***

TABLE OF CONTENTS

I. Executive Summary

In the December 30, 1999 *Federal Register*, the Minerals Management Service (MMS) proposes to tie royalty payments for oil produced on federal leases to the prices of benchmark crude oils. In the case of California crude oils, royalty payments for oil not transferred at arm's length are to be based on an Alaska North Slope (ANS) spot price index. The MMS would make allowances for location and quality differences between royalty crude oils and the index, but the methodology is ambiguous and could be extremely difficult to implement.

ANS is not a good basis for valuing California crude oils. ANS is a blend of crude oils produced in a wholly separate petroleum province and it is economically distinct from California crude oils. *Reuters*, *Telerate*, and *Platt's Oilgram* have collected spot price information on ANS delivered to California and the prices of several California crude oils for over a decade. Line 63, for example, is a California crude oil stream that has a similar API gravity and sulfur percentage to ANS. It is priced in the Los Angeles Basin not far from where ANS is landed. Both crude oils are widely traded by refiners in the region. Over the last decade, ANS has generally sold for a higher price than Line 63. Moreover, the difference in market value between the two crude oils fluctuated widely even after adjustments for gravity. Similar conclusions are drawn when ANS spot prices are compared to two heavier California crude oils, Wilmington and Kern River.

API gravity is the most frequently used measure to estimate the quality of a crude oil. Generally, heavy crude oils have a gravity of less than 20° and light crude oils measure more than 34°. Differences in API gravity are often used to estimate price differences among crude oils from the same or similar fields. They should not, however, be used to determine price differences across different crude oil families. Even though ANS is a medium gravity crude oil it has frequently sold for more than crude oils that are lighter.

The methodology underlying the MMS proposal would tie royalty values in non-arm's length sales to an index of either WTI or ANS prices. Using this methodology, prices are determined in market centers, and field values are determined by subtracting transportation costs and other adjustments from the delivered value. This methodology is not, however, appropriate for the crude oil market, where production from large fields may flow to a variety of market centers using a variety of transportation modes. In a multi-dimensional system of production and delivery, market value is determined by the complex interaction of many variables. These variables cannot usually be broken down into a simple formula to adjust for differences in quality and location.

The MMS proposal is aimed at simplifying the valuation of royalty crude oils, but it is unlikely to do so. If royalty values are to be based on market values, then price indexes, such as ANS, must be adjusted for market-based quality and location differentials. Even if these data were available, the MMS has not outlined adequate procedures for collecting such information. The choice of proxies for market-based adjustments—from posted price bulletins or pipeline gravity banks—could cause estimated royalty values to deviate significantly from market values. While the proposed procedures are intended to increase federal revenue, there is no guarantee of this outcome. In any case, the arbitrary calculation of quality and location adjustments is bound to be expensive, time consuming, and controversial.

The market value of a commodity is nothing more or less than what it will sell for in an open market. The best way to measure market value is to observe prices in actual transactions. This has been a guiding principal of royalty valuation for decades and it should not be abandoned. Crude oil is not a simple commodity and determining prices for the thousands of U.S. fields is no simple matter. Unfortunately, the MMS has rejected the industry's proposed "comparable sales model" which has the potential to yield reasonably accurate prices for production not sold at arm's length. The MMS's latest proposal has not simplified the problem of determining the royalty value of various crude oils; it has made it more complex.

II. Credentials, purpose of report, and summary

A. Credentials

I, Samuel A. Van Vactor, am an economist, President of Economic Insight, Inc. and researcher at the University of Cambridge, Scott Polar Research Institute. Formerly, I was an economist at the U.S. Treasury in Washington, D.C. and a senior economist at the International Energy Agency of the Organization for Economic Cooperation and Development (OECD) in Paris, France. My educational and professional background is detailed in my resume in Appendix A.

Since 1973 I have specialized in energy economics. I am the author or co-author of a number of books and articles concerning the petroleum market. These include *Competition In The Oil Industry*, "Retrospective on Oil Prices," "Prospective on World Energy Markets: Real Costs will Continue to Fall" and "Time to End the Alaska Oil Export Ban." Economic Insight's current publications include the *Energy Market Report*, a daily report on electricity pricing in North America.

I am a founding member of the International Association for Energy Economics; I have served on its board and chaired the 1993 North American conference in Seattle. I have been a consultant or advisor to the Internal Revenue Service, the Bonneville Power Administration, U.S. General Accounting Office, the Congressional Research Service, and state and local agencies in Alaska, California, Idaho, Oregon, and Washington. I have spoken on energy economics throughout the United States, and in Canada, Hungary, England, India, Singapore, South Africa, China, Japan, Australia, Venezuela and France.

Much of my research activity has concerned the West Coast oil market. I have been a consultant or advisor to the Alaska Senate finance committee, the North Slope Borough, NYMEX, the California Independent Producers Association, the Alaska North Slope producers, and various crude oil producers in California.

B. Purpose of the Report

The American Petroleum Institute (API), the Independent Petroleum Association of America, the Domestic Petroleum Council, and the U.S. Oil and Gas Association have asked me to review and comment on the Minerals Management Service's further supplementary proposed rule for Establishing Oil Value for Royalty Due on Federal Leases as published in the Federal Register on December 30, 1999. In particular, I have been asked to comment on the appropriateness and validity of using spot prices of Alaska North Slope (ANS) crude oil as an index against which to measure the value of various crude oils produced from Federal leases in California.

C. Summary of Findings

1. ANS, which is a blend of various crude oils produced on Alaska's North Slope, is economically distinct from California crude oils and is unsuitable for determining their royalty value unless market-based quality and location adjustments are applied.

2. Spot market data demonstrate that ANS crude oil is not comparable in quality to California crude oils of similar API gravity. Usually ANS commands a premium over California crude oils and the relative values of the two types of crude oil fluctuate substantially.

3. The MMS proposed pricing methodology is unfit for the crude oil market, where oil is frequently shipped in many directions. Although the methodological change may be intended to enhance royalty revenue it could just as easily reduce it.

4. The market value of a crude oil is determined by many factors. These include supply and demand for petroleum-based products, the quality of the oil, location of the sale, transportation alternatives, logistical

considerations, and the configuration of refineries prepared to process the feedstock.

5. Gravity-price differentials published in posting bulletins and used by pipelines for shipping California crude oils are intended to adjust for small differences in gravity from crude oils from the same or nearly identical fields. They should not be used to determine value differentials between dissimilar oil fields or when gravity differences are substantial.

6. In most instances, quality and location differentials in exchanges and buy-sell transactions are combined, rather than separately stated. The MMS methodology, which aims to calculate transportation costs and quality adjustments separately, would be quite cumbersome to implement for California crude oils.

7. Rather than simplifying Federal royalty valuation of non-arm's-length transactions, the MMS proposed methodology would make this valuation more difficult and subject to considerable controversy.

III. Alaska North Slope Crude Oil

A. Alaska's Oil Fields

ANS is mainly a blend of crude oils from seven fields on the North Slope of Alaska. The principal field is Prudhoe Bay, the largest oil field ever discovered in the United States. ANS production peaked in 1988 at about two million barrels per day. Despite the development of surrounding smaller fields and enhanced oil recovery in Prudhoe Bay, ANS production has declined since its peak. Production for 1999 will be just over one million barrels per day.

The quality of crude oil in the North Slope oil fields varies considerably. Kuparuk, the second largest field, is heavy, with an API gravity of about 22 degrees. One of the newest discoveries, Pt. McIntyre, is a high quality crude oil of approximately 40 degrees. The Prudhoe Bay field also has large quantities of natural gas. Two processing plants have been added which inject natural gas liquids (NGLs) into the crude oil stream, which has the effect of increasing API gravity. In addition, refineries in Alaska withdraw ANS from the Trans Alaska Pipeline System (TAPS). These refineries "top" the crude oil to make light petroleum products and return the residual to the pipeline where it is blended with the whole crude oil. The mix of crude oil, NGLs, and residuum constitutes the crude oil stream known as ANS.

Although the composition of ANS has changed slowly over time (in recent years becoming lighter), the quality of the blend is very predictable. The decline in production, however, has had a substantial impact on ANS trade. In 1988, the point of peak production, the West Coast could not absorb the combined production of ANS and California crude oils. The surplus had to be shipped to the Gulf Coast despite the high transportation costs entailed. The surplus put downward pressure on West Coast crude oil prices. Reduced ANS production combined with removal of the ban on crude oil exports has eliminated the glut. At the same time, however, it has reduced the volume of ANS sold and diminished its role as a price "marker" for the region.

Alaska's North Slope is a wholly different crude oil producing province as compared to California. ANS has different refining qualities from California crude oils. It is a waterborne crude oil landed at California's two largest refinery centers—the Los Angeles Basin (LAB) and the San Francisco Bay Area. ANS is handled separately from California crude oils. It is transported and stored separately, and to my knowledge it is not commingled with California crude oils until finally processed by refineries.

B. Spot Price Comparisons: ANS and California Crude Oil

ANS and California crude oils compete for utilization in California's refineries. However, since most California crude oil is much heavier than ANS there are few opportunities for a direct comparison of prices. One California crude oil stream that is not too different from ANS is "Line 63." This crude oil is also a commingled stream; it is similar in density and sulfur content. It is delivered in the L.A. basin, reasonably close to where ANS is landed. A comparison of spot prices for ANS and Line 63 crude oil in the 1990's shows that the market priced ANS more highly, and, further, that the price relationship between the two oils varied significantly from month to month. Table B-1 shows the unstable nature of this relationship, based on spot prices, the very source of the index that the MMS proposes to use. This table gives the monthly average spot prices published by Reuters for ANS-West Coast (Column 1) and Line 63 (Column 2). On average, ANS sold for $0.85 more than Line 63.

A direct price comparison can be somewhat misleading, because ANS has a slightly higher API gravity than Line 63. In Table B-1, the Line 63 price is "adjusted" to the ANS gravity (Column 4) using the gravity-price differential contained in the Chevron posting bulletins (Column 3). (Section VI explains why gravity adjustments by themselves are not adequate to explain differences in crude oil market prices.) Column 5 shows the difference in spot prices for these two crude oils. ANS has usually sold at a premium to gravity-adjusted Line 63 oil. The price differential has ranged from a low of -$0.19 in September 1990, to a high of $2.26 in

March 1992, for an average of $0.68 over the ten-year period. Figure B-2 graphs this differential over time, clearly demonstrating the variability of this price relationship.

Spot prices are also published for two additional California crude oils – Wilmington and Kern River. Table B-3 lists spot assessments for ANS and Wilmington crude oils from July 1990 through December 1999. Here a price comparison is not so easily made, because Wilmington crude oil is much heavier than ANS. Column [1] is the average price assessment of 29° ANS. Column [2] is 17° Wilmington. To make these prices comparable, the much heavier Wilmington crude oil spot prices must be adjusted upward to reflect the 12 degrees of difference. The third and fourth columns list gravity-price adjustments from Chevron's bulletins during the relevant time periods. Column [5] shows the gravity-adjusted Wilmington "price" at a 29° equivalent.

The results are similar to the comparison made between ANS and Line 63. Through this period, ANS spot price assessments at the landing dock were, on average, $1.03 per barrel higher than the gravity-adjusted Wilmington spot price assessment. This figure actually understates the quality difference, because ANS prices do not include offloading and other logistical costs of moving the crude oil to a refinery. The Wilmington field, on the other hand, is close to the refinery gate. The price series reflect even more variability than seen in the Line 63 ANS comparison.

Location was not an important factor in the price comparisons just made, since the points of delivery were within a few miles of each other, adjacent to a number of interconnected refineries. Most California crude oils are, however, produced some distance from the Los Angeles Basin or the Bay Area. In these instances it is difficult to untangle the impact of quality and location on price differences. The Kern River oil field, for example, is located in the eastern San Joaquin Valley, far from a point where ANS is delivered. Kern River oil is shipped west and north to the San Francisco refining center.[1] Adjusting for the differences in gravity using the gravity-price differential in Chevron's Kern River postings should (if the MMS approach is correct) yield a stable difference in price between the two oils, reflecting the difference in location or transportation costs. As Table B-4 demonstrates, however, the difference between the spot price of ANS and the gravity-adjusted spot Kern River price does not appear to represent solely a transportation cost difference.

C. Quality and Logistical Characteristics

Why are refiners willing to pay more for ANS than most California crude oils? In most instances it may simply be superior refining qualities (many of which are not

[1] Kern River oil is also refined in the Bakersfield area and is sometimes transported south to the L.A. basin refining area.

explained by API gravity differences). ANS can produce a higher proportion of gasoline, jet fuels, and diesel (the products most in demand) than can most California crude oils. But there are other factors too, such as sulfur content. ANS has frequently sold for prices similar to the landed price of Arabian Light, even though ANS is heavier.

Virtually all of California's high-volume refineries are located near tidewater. In such locations they can pivot between onshore pipeline deliveries of crude oil and offshore crude oils, such as ANS. Pipeline deliveries do not offer much flexibility; the pipelines connect particular crude oil fields to the refinery. The refiner is locked into specific production profiles of the onshore fields. Not much can be done about changes in quality or production rates. In contrast, once crude oil is loaded on a tanker it can be delivered to a multitude of refineries. Moreover, individual refineries located near tidewater may choose from a wide variety of cargoes, selecting the one best suited to balance current feedstocks. Tanker deliveries can be delayed or sped up. In short, a refiner or producer has considerably greater flexibility with waterborne deliveries than with pipeline deliveries.

ANS producers in particular have been advantaged by their ability to deliver the crude oil to a wide variety of refiners in their own or chartered tankers. Onshore crude oils have limited outlets and a scarcity of storage options. Even if the producer owns pipelines, the number of onshore buyers is restricted. This flexibility has given ANS producers a competitive advantage.

ANS has had another advantage: the oil is delivered in large volume shipments. On the other hand, California crude oils, particularly light and medium gravity crude oils, are spread throughout six producing regions. Purchases are most often arranged in small lots. Put simply, the transaction costs to the refiner are smaller on a per barrel basis when dealing with a high-volume crude oil, and this allows them to offer a higher price per barrel.

In marketing ANS, the producers have had the flexibility to choose among many buyers at refinery centers in Hawaii, Puget Sound, the Bay Area, and the Los Angeles Basin. And, if reasonable sales could not be made in these markets, the oil could be shipped to the Gulf Coast. This has allowed ANS to be marketed to those refiners that had the most immediate demand and were willing to pay the highest prices.

IV. The Problem of Index Pricing

The underlying theoretical structure proposed by the MMS values oil at the point of production by observing an index price in a market center and subtracting transportation costs and other allowed adjustments. Implicitly the methodology assumes a simple relationship between production, transportation, and quality. In fact, the North American crude oil market works in quite a different fashion.

Consider the heavy crude oil fields in California's central San Joaquin Valley. These fields produce nearly half of the state's total oil output. The Valley is cross-connected with a whole series of pipelines, trucking terminals and rail transport. For example, crude oil from the Midway Sunset field can be shipped to Bay Area refineries, the Los Angeles Basin, refineries in Bakersfield, and the California Coast for delivery to Puget Sound and elsewhere. For many years the crude oil could even be shipped to Texas through the All-American pipeline. The first question the MMS has to resolve is where is the market center? Which transportation costs should apply? Would market centers and transport costs vary from one producer to another? Does this mean that every producer would pay a different royalty value for the same oil? If the index were based on a crude oil with different refinery or economic characteristics how would quality adjustments be made?

In the complex and dynamic oil market, the market value of crude oil at its field will rarely correspond to the value at a particular market center less regulated or predetermined adjustments. The dynamics of the market would not easily accommodate the regulatory time lag. It has been the general presumption that index pricing would result in higher valuations for royalty purposes. This may or may not prove to be the case.

Domestic crude oil production is declining, particularly in well-developed provinces. Ownership of transportation facilities, rates of utilization, quality of production (of the oils at the leases and of the indexes), and many other factors are constantly changing. Since the proposed methodology is not based on actual market prices, it could yield a higher or lower payment.

V. Determinants of Crude Oil Value

A. Introduction

Crude oil, particularly California crude oil, is far from homogenous. The exact chemical composition of crude oil varies with every field and in some instances from pool to pool within a field. Quality differences have a significant impact on the cost of refining particular crude oils and on the types of products the oil will produce. Refiners do not treat one crude oil as an exact substitute for another; some oils are much more valuable than others are. What refiners will be willing to pay for a given crude oil depends on many factors. Some of these factors include the processing units in place at the refinery, the strength of demand for the products expected to be refined from the oil, the number and types of refinery feedstocks that might substitute for it, and processing costs specific to the particular crude oil.

Location is another important determinant of the price a refiner will offer for a crude oil in the field. If the oil is close at hand and can be quickly and cheaply moved, it will be worth more than one of equivalent quality that is a long distance away and/or requires expensive modes of transportation. However, as noted, the impact of location on crude oil field prices is complex. Not only does it depend on the location of the crude oil field, but also on the locations of multiple refiners that can process the oil, and the type of transportation available to move it.

B. Quality

The most commonly used measure of crude oil quality is a simple measure of density -- API gravity, a formula specified by the American Petroleum Institute. Sulfur and other characteristics are also taken into account by distinguishing between fields and various crude oil blends. The API gravity of most crude oil ranges from around ten degrees to sixty degrees or more for natural gasolines and natural gas liquids. A crude oil with an API gravity of less than twenty degrees is normally considered heavy; twenty degrees up to thirty-four degrees – medium; and, thirty-four degrees or higher is considered light. (Precise definitions vary with the petroleum province and marketing circumstances.)

Within a crude oil type, API gravity is a reasonable predictor of crude oil yield, i.e., the percentage of various petroleum products that can be refined using a simple distillation process. In less complex refineries heavy crude oils produce a preponderance of lower-valued residual or heavy fuel oil. Light crude oils produce a greater volume of higher-valued lighter products -- diesel, jet fuel, and gasoline. Table B-5 demonstrates the relationship between gravity and yield for thirteen California crude oils. As gravity rises the percentage of heavy fuel oil from simple distillation declines. The statistical correlation of the relationship is quite high and, all other things being equal, the higher the gravity of a crude oil, the greater its value.

The petroleum industry accounts for the impact of gravity on crude oil value through gravity-price differences in postings and gravity banks on pipelines. Typically, crude oil prices are discounted from 10 to 40 cents per degree below a given price level for every degree of gravity reduction. (Or added to the base price, if the gravity of the given crude oil is higher.) The gravity-price differential changes from time to time as market circumstances change. It is, however, important to note that gravity-price differentials published in postings and used in pipeline gravity banks are normally intended to measure relatively small variations in gravity within a given crude oil type. They are not intended to be applied across crude oil fields or used in circumstances where other important determinants of value vary.

Sulfur content is another important component of crude oil quality. The greater the percentage of sulfur (and other contaminants) the lower the quality of the crude oil and the lower its value. Volumetrically, sulfur reduces the Btu content of the oil; moreover, it is highly corrosive to refinery and logistical facilities and produces products lower in value. As a general rule, heavy crude oils tend to have a greater proportion of sulfur, because sulfur binds more easily to heavy molecules. The same is true for petroleum products; sulfur is usually concentrated in heavy fuel oils. Although it is generally true that heavy crude oils have a higher proportion of sulfur than lighter crude oils it is not always the case. This is why the percentage of sulfur associated with a crude oil is usually cited along with its gravity.

Viscosity (or resistance to flow) is another key aspect of crude oil quality. Crude oils that are highly viscous must either be heated or blended with lighter oils to move them through a pipeline. High viscosity crude oils tend to produce high viscosity fuel oils which are costly to transport and more difficult to burn. Gravity is not a particularly good predictor of the viscosity of a crude oil. Many medium gravity crude oils have a higher viscosity than do lower gravity oils.[2] In California, crude oils with gravity less than 20 degrees normally will not flow through an unheated pipeline without treatment.

In addition to gravity, sulfur, and viscosity there are a host of factors, knowable and unknowable, which contribute to the willingness of refiners to pay more or less for various crude oils.

C. Refining economics

When considering the impact of quality on refiners' willingness to buy particular crude oils and how much they will pay for them, it is important to understand that such demand is derived mainly from the value of the products the oil will produce. Consumers do not directly use crude oil; rather it is purchased by refiners who process it into gasoline, jet fuel, diesel, fuel oil, and other petroleum products. Obviously what refiners are willing to pay for crude oil depends on the cost of refining that crude oil and the revenue they receive from their refined products. Often rising crude oil prices are consequences of improved demand for gasoline or other petroleum products. Rising or falling petroleum product prices do not, however, have a uniform impact on all types of crude oil. If, for example, gasoline prices rise, or heavy fuel prices fall, there will be an impact on relative crude oil prices. The product price adjustments will cause some refiners to buy a lighter mix of crude oils as they seek to produce more gasoline and less heavy fuel oil. This, in turn, will likely cause the price differential between various crude oils to change; heavy crude oil prices will fall and light crude oil prices will rise. Similarly, an unexpected

[2] Chapter 7 of the *Fuel Oil Manual*, by Paul F. Schmidt (The Industrial Press, 1951) contains a detailed discussion of viscosity, pages 40-52.

breakdown in sulfur-removing equipment in a key refinery can change the relative value of “sour” and “sweet” crude oils.

There are a host of other issues with respect to the melange of crude oils available to refiners and the prices they are willing to offer. For example, high concentrations of nitrogen can cause poisoning of catalysts. High levels of contaminants in a refinery’s feedstock cause excessive wear and tear on the equipment. These and other problems can increase refining cost. Some of these features are noted in crude oil assays and some are not.

In addition to heavy concentrations of sulfur, many California crude oils are laden with heavy metals, acids, nitrogen, and other contaminants. These impurities adversely impact the prices of these crude oils, because refineries have to be specifically designed to process them and to deal with their corrosive characteristics. Although California heavy crude oil exports have been allowed since 1992,very little trade has developed, reflecting both the high cost of transport and the peculiar refining qualities of these oils.

The most important factor impacting California refining is the preponderance of heavy crude oils. The average API gravity of crude oil processed by California’s refineries is much heavier than in other regions. Approximately 70% of California crude oil production has API gravity of 20º or less. (See Table B-6.) California has little heavy industry, severe restrictions on burning sulfur-laden fuel oils, and the most stringent regulations on clean automobile fuels in the U.S. Thus, heavy, contaminant-laden fuel products either have to be exported or recycled for conversion to high-grade gasoline, diesel, jet fuel, and other light products that are in demand. Heavy oil conversion is a complex and costly process, and in the last decade the industry has spent billions of dollars to upgrade refinery facilities.

D. Location

The other important factor determining the price of crude oil in the field is its location. If a refiner has a choice of two nearly identical crude oils, the one with lower transport costs will be chosen, unless the more remote crude oil's field price is reduced to account for the higher transport cost.

Distance is not always the crucial factor in transportation costs, because there are several shipping modes with distinctly different combinations of variable and fixed costs. Generally the cheapest transport per mile is by marine supertanker. However, per-mile costs rise as shipment sizes diminish and distance contracts. Small coastal tankers or barges are often no cheaper than rail or truck, depending on specific location and infrastructure.

On land, crude oil pipelines are usually the least cost mode of shipment. Costs are, however, sensitive to the volume of crude oil being shipped and its quality. Crude oil pipelines that utilize only a small percentage of their capacity or must be heated in order to move high-viscosity crude oils can be quite expensive.

It is important to note that in one way or another, refiners **pay** for transportation whether they buy the crude oil at the lease or at the refinery gate. If they purchase crude oil at a lease and have no transport infrastructure they have to pay pipeline tariffs, tanker, rail, and/or truck charges. If they own transport facilities, they have to bear the cost of maintaining and running the equipment. If, on the other hand, a refiner buys the crude oil on a delivered basis, the same or similar costs must be borne by the seller and these costs are included in the sales price. The seller could have sold the crude oil at the lease at its market value – the price representing the royalty obligation. If instead the seller agrees to deliver the oil, transportation costs will be added to the lease value to derive a delivered price.

Crude oil fields, transportation infrastructure, and refineries all have specific locations. It is not possible to estimate generic transport costs and field values without knowing the details. However, it can be stated unequivocally that crude oil prices in the field are often substantially different than value at the refinery gate. These differences reflect not only the cost of moving the oil to the refinery but the numbers and type of market alternatives and conditions facing refiners and producers.

VI. Market-based Quality and Location Adjustments

A. Introduction

The Minerals Management Service proposes to use average ANS spot prices, adjusted for location and quality differentials, and transportation costs, to value California oil from federal leases sold under non-arm's-length contracts. In this version of the proposed rule the MMS has not indicated how such location and quality differentials are to be calculated (although it might be inferred that they intend to use price-gravity differentials from posted price bulletins and/or pipeline gravity banks). More importantly, the MMS has not demonstrated an understanding of the difficulty of developing and maintaining a valid system of quality and location differentials. Nor does there appear to be an appreciation of the potential arbitrariness of differentials that must be submitted by the lessee and agreed to by the MMS for each field, and that these differentials would need to be constantly changing to reflect the dynamics of the marketplace.

B. Gravity-price adjustments inadequately explain value differences

Although the methodology to be used for quality and location differentials is not clearly specified in these proposed rules, earlier versions have indicated that a gravity-price adjustment based on posted price schedules and/or pipeline gravity bank parameters would be appropriate.[3] However, the type of gravity-price adjustments suggested by the MMS cannot be used to reconcile the differences in the market value between ANS and California crude oils.

Currently, several companies including Chevron, Union/Tosco, ExxonMobil, Texaco/Equiva, Koch, and Enron (EOTT) publish posted price schedules for California fields. Prices are published independently for crude oils that the posting companies purchase or expect to purchase. The bulletins list crude oil fields, API gravity, and prices per barrel. Different gravity-price adjustments are listed for different gravity ranges. Typically the adjustments for heavy crude oils are greater than for lighter crude oils. Crude oils with API gravity greater than 40° usually have no price adjustment at all.

It is easy to misunderstand the meaning of the gravity-price adjustment. Although the API gravity of California crude oils varies considerably from field to field, production from individual leases is usually quite consistent. There are a few exceptions, but as a general rule if the source of the crude oil is known, its gravity will fall within a predictably narrow range. In instances where gravity does vary within a field from one lease to another, posted price bulletins often contain two different levels of API gravity and two different prices for the same field. For example, Mobil posts a price for 13° South Belridge (for oil under 28°) and 31° South Belridge (for oil above 28°).

Prices actually paid for the various crude oils are adjusted in accordance with gravity variation as per the published scale. These price adjustments are, however, only intended to be applied to variations in gravity for the same crude oil. They are not intended for use in adjusting or comparing prices from one field to another. This is because the sulfur content, location and other important determinants of value vary significantly from field to field. API gravity is a reasonable predictor of crude oil quality within a field, but not across fields. The posting bulletins themselves can be used to demonstrate the difficulties inherent in the use of gravity adjustments between fields to derive prices. For example, the Wilmington field and the Long Beach (Signal Hill) field are located in the Los Angeles Basin, adjacent to each other. In the Tosco posting bulletin for September 3, 1998, there is a \$2.40 difference in the price of oil from these two fields, of which only \$1.80 can be accounted for with a simple

[3] The Orders to Pay issued by the MMS to various companies for alleged underpayment of royalties on federal leases in California have also applied a simple gravity-price adjustment between California crude oil and ANS as a method of calculating quality differentials.

gravity-price adjustment. This leaves $0.60 that must reflect other quality differences. The specifics of this example and others are shown in Appendix C.

Another way to demonstrate the dissimilarity of ANS and California crude oils is to view observed price differences *as if* they reflected a gravity-price differential. A good way to do that is to return to the earlier example comparing the price of ANS to Line 63, the California crude oil most similar in terms of gravity, sulfur and location. If the market considered ANS and Line 63 to be close substitutes, then the difference in spot prices would be expected to reflect the slight differences in gravity between the two oils. Thus, one could impute a gravity-price differential based on monthly price differences. Figure B-7 compares the results of this calculation with the gravity price differential contained in Chevron posting bulletins during the 1990s. The imputed gravity-price differential derived from the spot price series for ANS and Line 63 gyrates wildly from month to month.

Using ANS as an index for pricing California crude oils involves adjustments that attempt to equate oils not from the same field, or even nearby or similar fields, but rather to oil from an entirely separate oil province.[4] Such comparisons are clearly problematic. As has been shown, even in the simplest case, ANS spot prices do not offer a reliable index for valuing California crude oils. The relationships among market determined prices are much more complex than the proposed rules would suggest.

C. Sulfur and Other Quality Differentials

The price comparisons in Section III demonstrate the difficulties in comparing ANS spot prices and spot price series for California crude oil. However, these comparisons do not address the need to adjust for other quality issues that influence the value of the oil. The four series used are for oils that are fairly similar in terms of sulfur content. The Reuters price series sets the sulfur percentages as follows: ANS (1.1% sulfur), Line 63 (1%), Wilmington (1.5%), and Kern River (1.2%). As noted earlier, the range of sulfur in California is wide, with Outer Continental Shelf oil and the Santa Maria Valley having particularly high concentrations of sulfur. There is little if any market-based information on the discounts specifically associated with sulfur content. Although certain pipeline gravity banks may contain some adjustment standards, these adjustment mechanisms are valid only for small differences. Pipeline users are restricted in the range of sulfur that is allowed, with high sulfur and high

[4] In the United States, California, the Gulf Coast and Alaska's North Slope, are often referred to as distinctly separate geological provinces. Within each province there may be multiple basins. Production within each basin or province is sometimes referred to as crude oil family and may have some common characteristics, even though individual fields can still be quite different. Fields and areas as defined by geologists and as understood in the oil industry are smaller demarcations than are basins, districts and provinces.

viscosity oil accepted for shipment only in batch mode. Shippers are not allowed to put in high sulfur oil and extract lower sulfur grade simply by paying a sulfur penalty. Since no spot prices are collected for high sulfur California crude oils, there is no obvious adjustment that can be translated into a sulfur differential for oil from offshore federal leases not transferred at arm's length. Similarly, information to objectively calculate the market-based differential based on heavy metals or nitrogen content of the wide variety of California crude oils is unavailable.

D. Industry Practice in Valuing California Crude Oil

Clearly, the MMS wishes to move away from the heavy emphasis placed on posted prices encompassed in the 1988 rules for establishing royalty value. And, yet, postings contain unique information about the relative values of crude oil. Even the MMS's consultants have indicated that postings are an accurate reflection of the distinct quality and location differences from one field to another. In their report to the MMS, they stated that: "While the absolute level of California posted prices does not reflect market value, differences in posted prices approximate quality and location differences between crudes. The use of posted prices to establish quality and location differentials between crudes is supported by their use in exchange transactions."[5] The MMS proposed rules would replace that information with a system in which these differentials would be developed administratively by the lessees in negotiations with the MMS or by adjustments determined through regulation.

The rationale for substituting spot prices for postings as a determinant of value for non-arm's length sales further states that "Today, spot prices are readily available to industry participants via price reporting services, and these and similar prices play a significant role in crude oil marketing in terms of the basis upon which deals are negotiated and priced."[6] Whereas, this statement may be correct as a generalization, it is not accurate with respect to the valuation of California crude oils. Although three spot price series are published for California crude oils, these series are for oils that do not cover the full range and variety of crude oil necessary to value oil from federal leases in California. ANS spot prices are available, but as has been demonstrated here, ANS is not similar to the majority of California oil in quality, location or market valuation. Appendix D summarizes the published spot prices of California crude oils and the methodology used in the collection of these prices.

If, indeed, it were possible to make appropriate market-based quality, location and transportation adjustments to the ANS spot price to reflect the differences with

[5] "California Crude Values Study," prepared for Minerals Management Service by Micronomics, Inc. November 1995, p. 11.

[6] 64 Fed. Reg. 73821 (December 30, 1999).

each field's oil production, then ANS could serve as an index for valuation. This is however simply a tautology. With appropriate adjustments, anything could serve as an index. The crux of the matter is how and what those adjustments would be, and the likelihood of being able to develop them fairly and efficiently. In our review of transactions data and industry practice, we find no indication that term contracts for the sale or purchase of California crude oil are routinely based on ANS spot prices. Contracts for purchase or sale of ANS are often based on ANS spot prices, but this is hardly the same thing. Since there is no systematic relationship between spot prices (or posted prices) for California oil and ANS, ANS cannot easily serve as an index. If ANS were the index and if the adjustment differentials were intended to reflect market realities, then these differentials would be exceedingly complex, constantly changing, and perhaps, endlessly controversial.

VII. Market Value

The market value of a commodity is nothing more or less than what it will sell for in an open market. The best way to measure market value is to observe prices in actual transactions. This has been a guiding principal of royalty valuation for decades and it should not be abandoned. Systems that attempt to administer prices or anticipate market outcomes, even for the simplest of commodities, invariably collapse.

Crude oil is not a simple commodity. The *Oil and Gas Journal* lists 33,179 separate crude oil fields in the United States. Conceivably, oil from each of these fields has its own peculiar refining qualities and transportation options. Determining prices for these fields is no simple matter, but it is something the market has done for over a century. Unfortunately, the MMS has rejected the industry's proposed "comparable sales model" which has the potential to yield reasonably accurate prices for production not sold at arm's length.

The MMS's latest proposal has not simplified the problem of determining the royalty value of various crude oils; it has made it more complex. Information on market-based quality and location differentials would be even more difficult to collect and verify than actual transactions prices from comparable sales. The MMS would be left with two basic approaches. First, they could base royalty values on index prices with adjustments for location and quality negotiated with each of the royalty producers. This would almost certainly result in different valuations for different producers, by definition deviating from the concept of basing royalties on market value. Alternatively, the MMS could proceed with a utility-style cost build-up of transportation and quality differentials, to be subtracted from or added to index prices. As demonstrated, however, such a regulatory approach could result in royalty valuations of California crude oils that are significantly different than their market values. It is also worth adding that if the MMS's proposal is unworkable in California it is likely to be just as arbitrary everywhere else. Despite the superficial appeal, price indexes are simply unsuitable for determining royalty values for the multitude of individual crude oil fields in which the federal government has an interest.

APPENDIX CONTENTS

Appendix A

Samuel A. Van Vactor

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Professional Experience

President, Consulting Economist, Economic Insight, Inc. (EII), Portland, Oregon, 1981 to present, and Researcher at the University of Cambridge, UK.
EII publishes the *Energy Market Report* on the electric power market and provides economic consulting services. The firm averages about ten employees. It collects and organizes economic data, conducts research, undertakes policy analysis and provides expert witness services for anti-trust, tax and regulatory hearings. Recent projects have included analysis of crude oil royalty obligations in the United States for Texaco, Unocal and Exxon; analysis of natural gas market developments in Asia for the Asia Pipeline Research Society of Japan; testimony on behalf of the California Power Exchange before the Federal Energy Regulatory Commission (FERC); and analysis for the California Power Exchange on bilateral power trading, the structure of the Western Power Market, and the development of the exchange's new products and services.

Research Associate, Portland State University, October 1979 to December 1981 .
Mr. Van Vactor taught two courses in energy economics and managed several federal grants related to energy and economic issues in the Pacific Northwest.

Director of Planning, Oregon Department of Energy, **October 1978 to October 1979.**
Mr. Van Vactor managed a group of six engineers and economists evaluating energy policy options for the State of Oregon.

Senior Economist, International Energy Agency (IEA) of the OECD , **Paris, France, October 1975 to October 1978.**
Mr. Van Vactor helped design and implement the agency's country studies program.

International Economist, U.S. Treasury Department, **August 1973 to October 1975.**
Mr. Van Vactor was a policy analyst for the Secretary of the Treasury, and advised him on issues related to oil pricing and energy demand. Mr. Van Vactor also assisted in the development of a series of domestic energy policy documents, and was a member of the negotiating team for long-term energy cooperation between the U.S. and other industrialized countries.

Education

Ph.D. Candidate, **Cambridge University, U.K.**
Research, **London School of Economics, U.K.**
M.A., Economics, **University of Washington, U.S.A.**
B.S., Economics, **University of Oregon, U.S.A.**

Significant Publications

I. Contributions were made to the following government publications and reports, including primary authorship of some:

Energy Conservation in the International Energy Agency , 1976 Review, *OECD, Paris, September 1976.*

World Energy Outlook, OECD, Paris, 1977.

Energy Policies and Programs of IEA Countries , 1977 and 1978 Reviews OECD, Paris

Oregon's Energy Future, January 1979.

"Oil Shortages," Oregon Department of Energy, May 1979.

The United States Exerts Limited Influence on the International Crude Oil Spot Market , Report to the Congress by the Comptroller General, US General Accounting Office, August 21, 1980.

Gasoline Demand in the Pacific Northwest, *The Pacific Northwest Supply System* and *Petroleum in the Pacific Northwest: Disruption or Transition* , NW Energy Policy Workshop, 1980.

Alaska's Long-Term Energy Plan, Division of Energy Power and Development, Alaska Department of Commerce, April 1981.

An Energy Emergency Contingency Plan for Alaska , Division of Energy Power and Development, Alaskan Department of Commerce, September 1981.

Fuel Prices in the Northwest, Long-term oil and gas price Forecast for the Northwest Power Planning Council, September 1982.

II. Author or co-author for the following books, articles and speeches:

Competition in the Oil Industry, (NSF funded project at George Washington University,) January 1976, with William A. Johnson and Richard E. Messick.

"Energy Conservation in the OECD, Progress and Results," *The Journal of Energy and Development*, Spring 1978 and International Comparisons of Energy Consumption, Resources for the Future, 1978.

"OPEC in Crisis," a paper delivered at the November 1982 annual meeting of the International Association of Energy Economists.

"World Oil Markets," a paper delivered at the January 1984 annual meeting of the International Association of Energy Economists, with Arlon R. Tussing.

"Mergers and Acquisitions in the Petroleum Industry," published in Papers and Proceedings of the Eighth Annual North American Conference, IAEE, at MIT, November 1986.

"Retrospective on Oil Prices," a paper for delivery at the Western Economic Association Meeting, July 1986 and published in *Contemporary Policy Issues*, July 1987 with Arlon R. Tussing.

"Evolution of Bulk-Power Markets," A paper for delivery at the International Association of Energy Economists, Annual Meeting, Calgary Alberta, July 1987.

"U.S./Canada Trade and Energy: Learning from Past Mistakes," *Forces*, Winter 1988 with Arlon R. Tussing.

"The International Oil Market in 1988," Presentation to The Conference Board of Canada's Business Outlook 1988 Conference, Calgary Alberta, May 1988.

"Is an Oil Tariff Justified? An American Debate: I. Reality Says No," *The Energy Journal*, July 1988 with Arlon R. Tussing.

"Spot and Contract Markets in the Petroleum Industry," with Ronald D. Ripple, a paper delivered at the International Association of Energy Economics, Annual Meeting, Caracas, June 1989.

"Prospective on World Energy Markets: Real Costs Will Continue to Fall," published in the *OPEC Review*, Summer 1990 with Arlon R. Tussing.

PADD V in Transition: Strategic Evaluation of Oil Industry Prospects in the 1990s , November, 1992 published with Energy Security Analysis, Inc.

"Time to End the Alaska Oil Export Ban," published by the Cato Institute, May 1995.

"Natural Gas Deregulation in South Africa: A Wolf in Sheep's Clothing," 1995-1996 with William A. Johnson. Presentation May 1996, Budapest Hungary, International Conference of the IAEE.

"Power Trading: The Race is On," April 1996, with Dona K. Lehr. Speeches in San Diego for Executive Enterprises, Denver for Infocast, and Washington DC and Los Angeles for the IAEE.

"The Demand for Gas in a Coal-Based Energy Economy." with Ronald D. Ripple. Paper for the Northeast Asian Natural Gas Pipeline: Possibilities and Prospects, Beijing, China, September 1996.

"Evolution of Wholesale Power Price Structures in the Western Power Market," with Dona K. Lehr. in *The Evolving U.S. Power Market,* Risk Publications, June 1997.

"Commoditisation" in *The Evolving U.S. Power Market,* Risk Publications, June 1997.

"Natural Gas Projects in Asia and the Development of Asian Gas Trunk Pipelines," for the Financial Times Conference on Asian Gas , June 5-6 1997, Singapore, with Arlon R. Tussing.

"South Korea's Thirst of Gas," with Arlon Tussing, *Financial Times Energy Economist*, March 1998.

"Enhancing Private Investment in the Natural Gas Industry in Asia," in *Natural Gas in Asia: Facts and Fiction*, for PECC Energy Forum, November, 1998.

"Power Exchanges," Presentation and analysis for the Electric Power Research Institute's Senior Executive Management Roundtable, November 2, 1998.

"Electricity Restructuring in North America," *Financial Times Energy Economist*, December, 1998.

Appendix B
Figures and Tables

Table B-1
Comparison of Reuters Spot Prices: ANS and Line 63 Crude Oil

Date	West Coast ANS at 29° API ($/bbl.) [1]	Line 63 at 28° API ($/bbl.) [2]	Gravity Adjustment, 20-33° API ($/deg. API)^ [3]	Line 63 Adjusted to 29° API ($/bbl.) [4] = [2]-1*[3]	Difference ANS - Line 63 at 29° API ($/bbl.) [5]=[1]-[4]
Jul-90	$15.52	$14.81	$0.20	$15.00	$0.51
Aug-90	$26.01	$25.44	$0.29	$25.73	$0.28
Sep-90	$31.95	$31.84	$0.30	$32.14	-$0.19
Oct-90	$31.59	$30.92	$0.32	$31.23	$0.35
Nov-90	$28.72	$27.89	$0.25	$28.14	$0.58
Dec-90	$23.71	$22.98	$0.34	$23.32	$0.39
Jan-91	$20.74	$20.25	$0.23	$20.48	$0.26
Feb-91	$15.70	$15.53	$0.25	$15.78	-$0.08
Mar-91	$16.99	$16.63	$0.25	$16.88	$0.11
Apr-91	$17.58	$16.89	$0.25	$17.14	$0.43
May-91	$16.73	$16.29	$0.25	$16.54	$0.19
Jun-91	$16.29	$15.88	$0.21	$16.09	$0.19
Jul-91	$17.33	$16.47	$0.20	$16.67	$0.66
Aug-91	$17.18	$16.22	$0.25	$16.47	$0.71
Sep-91	$17.35	$16.45	$0.25	$16.70	$0.65
Oct-91	$18.54	$17.67	$0.27	$17.95	$0.59
Nov-91	$17.46	$16.52	$0.25	$16.77	$0.70
Dec-91	$14.88	$13.59	$0.15	$13.74	$1.14
Jan-92	$14.94	$13.09	$0.15	$13.24	$1.69
Feb-92	$15.33	$13.14	$0.15	$13.29	$2.04
Mar-92	$15.49	$13.08	$0.15	$13.23	$2.26
Apr-92	$16.97	$14.71	$0.15	$14.86	$2.11
May-92	$18.09	$16.85	$0.15	$17.00	$1.09
Jun-92	$20.23	$19.35	$0.15	$19.50	$0.73
Jul-92	$19.42	$18.69	$0.15	$18.84	$0.57
Aug-92	$18.00	$17.05	$0.15	$17.20	$0.80
Sep-92	$18.48	$17.58	$0.15	$17.73	$0.74
Oct-92	$18.80	$17.35	$0.15	$17.51	$1.29
Nov-92	$17.42	$15.69	$0.19	$15.88	$1.54
Dec-92	$16.37	$14.51	$0.15	$14.66	$1.71
Jan-93	$15.59	$13.98	$0.15	$14.13	$1.46
Feb-93	$16.81	$15.30	$0.15	$15.45	$1.36
Mar-93	$17.38	$16.12	$0.15	$16.27	$1.11
Apr-93	$18.22	$17.26	$0.15	$17.41	$0.81
May-93	$17.46	$17.12	$0.15	$17.27	$0.19
Jun-93	$16.04	$15.75	$0.15	$15.90	$0.14
Jul-93	$14.79	$13.95	$0.15	$14.10	$0.69
Aug-93	$15.44	$14.48	$0.15	$14.63	$0.81
Sep-93	$15.01	$14.13	$0.15	$14.28	$0.73
Oct-93	$15.45	$14.60	$0.15	$14.75	$0.70
Nov-93	$13.02	$12.24	$0.15	$12.39	$0.63
Dec-93	$10.39	$9.98	$0.15	$10.13	$0.26
Jan-94	$11.64	$11.36	$0.15	$11.51	$0.13
Feb-94	$12.56	$12.30	$0.15	$12.45	$0.12
Mar-94	$12.86	$12.60	$0.15	$12.75	$0.11
Apr-94	$14.91	$14.55	$0.15	$14.70	$0.21
May-94	$16.41	$15.97	$0.15	$16.12	$0.29
Jun-94	$16.46	$15.91	$0.14	$16.05	$0.40

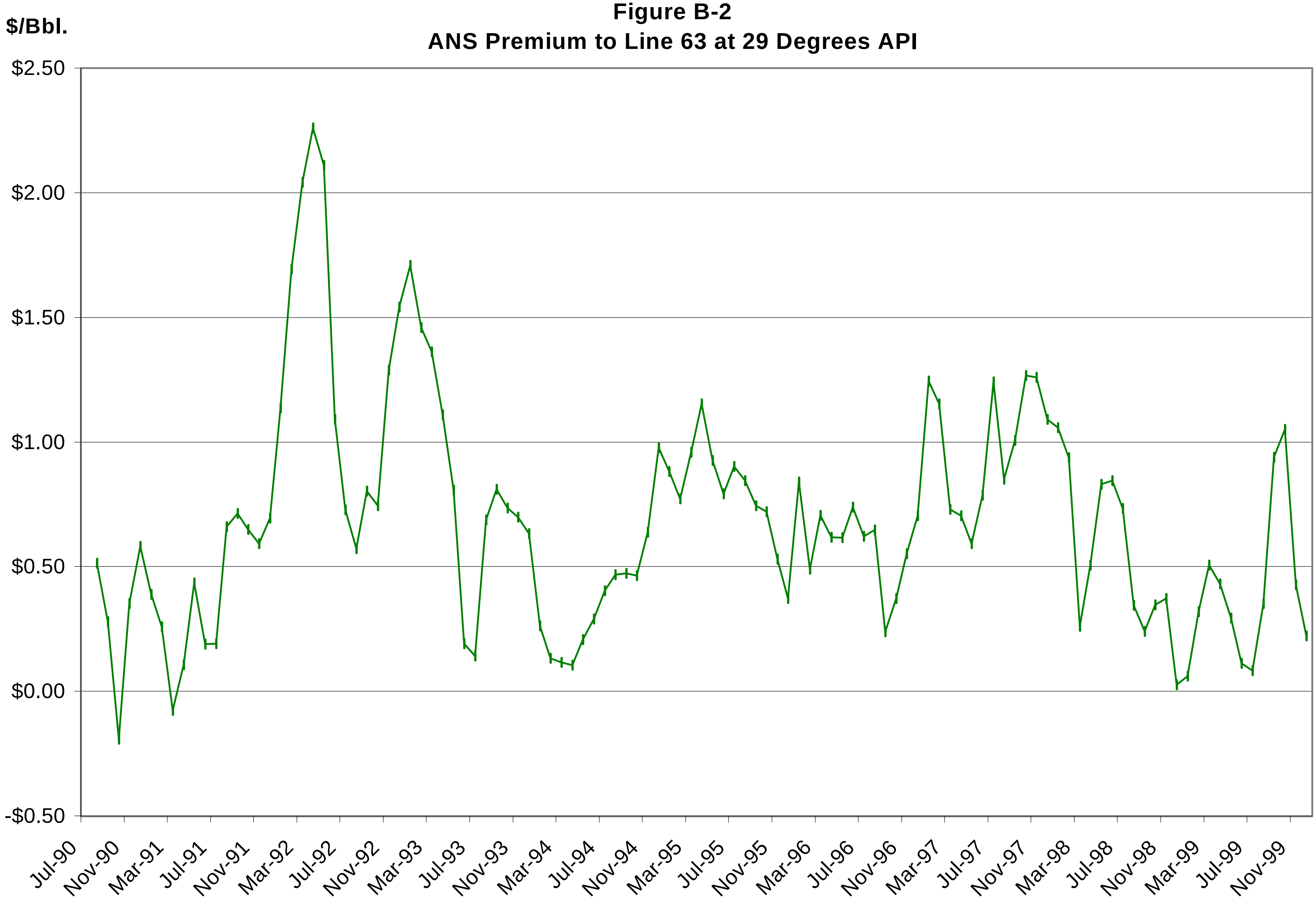
Date	West Coast ANS at 29° API ($/bbl.)	Line 63 at 28° API ($/bbl.)	Gravity Adjustment, 20-33° API ($/deg. API)[A]	Line 63 Adjusted to 29° API ($/bbl.)	Difference ANS - Line 63 at 29° API ($/bbl.)
	[1]	[2]	[3]	[4] = [2]-1*[3]	[5]=[1]-[4]
Jul-94	$16.54	$15.94	$0.13	$16.07	$0.47
Aug-94	$16.69	$16.06	$0.15	$16.21	$0.47
Sep-94	$16.11	$15.50	$0.15	$15.65	$0.46
Oct-94	$16.01	$15.22	$0.15	$15.37	$0.64
Nov-94	$16.64	$15.52	$0.15	$15.67	$0.98
Dec-94	$15.50	$14.47	$0.15	$14.62	$0.88
Jan-95	$16.21	$15.29	$0.15	$15.44	$0.77
Feb-95	$17.19	$16.08	$0.15	$16.23	$0.96
Mar-95	$17.29	$15.98	$0.15	$16.13	$1.15
Apr-95	$18.37	$17.34	$0.10	$17.44	$0.93
May-95	$18.37	$17.48	$0.10	$17.58	$0.79
Jun-95	$17.47	$16.47	$0.10	$16.57	$0.90
Jul-95	$16.27	$15.33	$0.10	$15.43	$0.85
Aug-95	$16.70	$15.85	$0.10	$15.95	$0.74
Sep-95	$16.68	$15.86	$0.10	$15.96	$0.72
Oct-95	$15.96	$15.33	$0.10	$15.43	$0.53
Nov-95	$15.89	$15.38	$0.14	$15.52	$0.37
Dec-95	$17.03	$16.04	$0.15	$16.19	$0.84
Jan-96	$17.29	$16.68	$0.12	$16.80	$0.49
Feb-96	$17.83	$17.02	$0.10	$17.12	$0.71
Mar-96	$20.35	$19.63	$0.10	$19.73	$0.62
Apr-96	$22.01	$21.25	$0.15	$21.39	$0.62
May-96	$19.60	$18.66	$0.20	$18.86	$0.74
Jun-96	$18.95	$18.12	$0.20	$18.32	$0.62
Jul-96	$19.74	$18.86	$0.23	$19.09	$0.65
Aug-96	$19.94	$19.45	$0.25	$19.70	$0.24
Sep-96	$21.71	$21.09	$0.25	$21.34	$0.37
Oct-96	$22.58	$21.78	$0.25	$22.03	$0.55
Nov-96	$21.40	$20.49	$0.21	$20.69	$0.70
Dec-96	$23.57	$22.13	$0.20	$22.33	$1.24
Jan-97	$23.62	$22.27	$0.20	$22.47	$1.15
Feb-97	$21.07	$20.10	$0.24	$20.34	$0.73
Mar-97	$20.08	$19.17	$0.21	$19.37	$0.70
Apr-97	$18.48	$17.68	$0.20	$17.88	$0.59
May-97	$19.32	$18.40	$0.13	$18.54	$0.79
Jun-97	$17.26	$15.87	$0.15	$16.02	$1.24
Jul-97	$17.51	$16.51	$0.15	$16.66	$0.85
Aug-97	$18.01	$16.91	$0.10	$17.01	$1.01
Sep-97	$18.12	$16.75	$0.10	$16.85	$1.27
Oct-97	$19.60	$18.24	$0.10	$18.34	$1.26
Nov-97	$18.34	$17.15	$0.10	$17.25	$1.09
Dec-97	$16.43	$15.27	$0.10	$15.37	$1.06
Jan-98	$14.78	$13.73	$0.12	$13.84	$0.94
Feb-98	$13.37	$12.95	$0.16	$13.11	$0.26
Mar-98	$12.27	$11.59	$0.18	$11.77	$0.51
Apr-98	$12.53	$11.55	$0.15	$11.70	$0.83
May-98	$12.33	$11.34	$0.15	$11.49	$0.84
Jun-98	$11.67	$10.79	$0.15	$10.94	$0.73
Jul-98	$13.02	$12.53	$0.15	$12.68	$0.34
Aug-98	$12.55	$12.16	$0.15	$12.31	$0.24
Sep-98	$14.19	$13.69	$0.15	$13.84	$0.35

Date	West Coast ANS at 29° API ($/bbl.)	Line 63 at 28° API ($/bbl.)	Gravity Adjustment, 20-33° API ($/deg. API)[A]	Line 63 Adjusted to 29° API ($/bbl.)	Difference ANS - Line 63 at 29° API ($/bbl.)
	[1]	**[2]**	**[3]**	**[4] = [2]-1*[3]**	**[5]=[1]-[4]**
Oct-98	$13.42	$12.90	$0.15	$13.05	$0.37
Nov-98	$11.51	$11.34	$0.15	$11.49	$0.03
Dec-98	$9.36	$9.20	$0.10	$9.30	$0.06
Jan-99	$10.78	$10.36	$0.10	$10.46	$0.32
Feb-99	$10.47	$9.86	$0.10	$9.96	$0.51
Mar-99	$13.08	$12.52	$0.12	$12.65	$0.43
Apr-99	$15.61	$15.17	$0.15	$15.32	$0.29
May-99	$15.83	$15.57	$0.15	$15.72	$0.11
Jun-99	$15.92	$15.69	$0.15	$15.84	$0.08
Jul-99	$18.36	$17.85	$0.15	$18.00	$0.35
Aug-99	$20.20	$19.07	$0.19	$19.26	$0.94
Sep-99	$22.90	$21.65	$0.20	$21.85	$1.05
Oct-99	$21.84	$21.21	$0.20	$21.41	$0.43
Nov-99	$23.61	$23.19	$0.20	$23.39	$0.22
Dec-99	$24.53	$24.03	$0.20	$24.23	$0.30
Average	$17.39	$16.54	$0.17	$16.71	
				mean difference	$0.68
				min difference	-$0.19
				max difference	$2.26
				std dev difference	$0.45

Sources: [1],[2]: Reuters
[3]: Chevron Posted Price Bulletins

Notes : A: When multiple gravity adjustments are given in a month, a daily weighted average adjustment is com
-Monthly prices are a simple average of daily average prices. Line 63 spot price published at 28°, is "ad
29° (the gravity at which Reuters publishes its spot price for ANS) using the gravity price differential fro
posting bulletins.

Figure B-2
ANS Premium to Line 63 at 29 Degrees API



Economic Insight, Inc.

Table B-3
Comparison of Reuters Spot Prices: ANS and Wilmington Crude Oil

Date	West Coast ANS at 29° API ($/bbl.)	Wilmington at 17° API ($/bbl.)	Gravity Adjustment 0-19° API ($/deg. API)[A]	Gravity Adjustment 20-33°API ($/deg. API)[A]	Wilmington Adjusted to 29° API ($/bbl.)	Difference ANS - Wilm. at 29° API ($/bbl.)
	[1]	[2]	[3]	[4]	[5] = [2]+3*[3]+9*[4]	[6]=[1]-[5]
Jul-90	$15.52	$11.01	$0.20	$0.20	$13.39	$2.13
Aug-90	$26.01	$22.17	$0.29	$0.29	$25.67	$0.33
Sep-90	$31.95	$25.37	$0.30	$0.30	$28.93	$3.02
Oct-90	$31.59	$27.14	$0.32	$0.32	$30.95	$0.64
Nov-90	$28.72	$24.13	$0.25	$0.25	$27.13	$1.59
Dec-90	$23.71	$19.21	$0.34	$0.34	$23.34	$0.37
Jan-91	$20.74	$16.97	$0.23	$0.23	$19.76	$0.99
Feb-91	$15.70	$13.38	$0.25	$0.25	$16.38	-$0.68
Mar-91	$16.99	$12.65	$0.25	$0.25	$15.65	$1.34
Apr-91	$17.58	$13.73	$0.25	$0.25	$16.73	$0.85
May-91	$16.73	$14.35	$0.25	$0.25	$17.35	-$0.61
Jun-91	$16.29	$14.30	$0.21	$0.21	$16.82	-$0.54
Jul-91	$17.33	$14.21	$0.20	$0.20	$16.65	$0.69
Aug-91	$17.18	$14.05	$0.25	$0.25	$17.05	$0.14
Sep-91	$17.35	$14.04	$0.25	$0.25	$17.04	$0.32
Oct-91	$18.54	$14.35	$0.27	$0.27	$17.64	$0.90
Nov-91	$17.46	$14.42	$0.25	$0.25	$17.42	$0.05
Dec-91	$14.88	$12.76	$0.15	$0.15	$14.56	$0.32
Jan-92	$14.94	$11.28	$0.15	$0.15	$13.08	$1.86
Feb-92	$15.33	$11.13	$0.15	$0.15	$12.93	$2.40
Mar-92	$15.49	$11.10	$0.15	$0.15	$12.90	$2.59
Apr-92	$16.97	$12.20	$0.15	$0.15	$14.00	$2.97
May-92	$18.09	$14.37	$0.15	$0.15	$16.17	$1.92
Jun-92	$20.23	$16.92	$0.15	$0.15	$18.72	$1.51
Jul-92	$19.42	$17.54	$0.15	$0.15	$19.34	$0.07
Aug-92	$18.00	$16.13	$0.15	$0.15	$17.93	$0.07
Sep-92	$18.48	$15.64	$0.15	$0.15	$17.44	$1.04
Oct-92	$18.80	$15.45	$0.15	$0.15	$17.29	$1.51
Nov-92	$17.42	$14.26	$0.19	$0.19	$16.54	$0.88
Dec-92	$16.37	$13.12	$0.15	$0.15	$14.92	$1.45
Jan-93	$15.59	$12.54	$0.15	$0.15	$14.34	$1.25
Feb-93	$16.81	$12.90	$0.15	$0.15	$14.70	$2.11
Mar-93	$17.38	$13.74	$0.15	$0.15	$15.54	$1.84
Apr-93	$18.22	$14.46	$0.15	$0.15	$16.26	$1.96
May-93	$17.46	$15.34	$0.15	$0.15	$17.14	$0.32
Jun-93	$16.04	$14.70	$0.15	$0.15	$16.50	-$0.46
Jul-93	$14.79	$12.37	$0.15	$0.15	$14.17	$0.62
Aug-93	$15.44	$12.25	$0.15	$0.15	$14.05	$1.40
Sep-93	$15.01	$12.10	$0.15	$0.15	$13.90	$1.11
Oct-93	$15.45	$12.60	$0.15	$0.15	$14.40	$1.04
Nov-93	$13.02	$11.42	$0.15	$0.15	$13.22	-$0.20
Dec-93	$10.39	$9.16	$0.15	$0.15	$10.96	-$0.56
Jan-94	$11.64	$9.18	$0.15	$0.15	$10.98	$0.67
Feb-94	$12.56	$9.86	$0.15	$0.15	$11.66	$0.90
Mar-94	$12.86	$10.45	$0.15	$0.15	$12.25	$0.61
Apr-94	$14.91	$11.58	$0.15	$0.15	$13.38	$1.53
May-94	$16.41	$13.16	$0.15	$0.15	$14.96	$1.46
Jun-94	$16.46	$14.22	$0.14	$0.14	$15.92	$0.53
Jul-94	$16.54	$14.50	$0.13	$0.13	$16.07	$0.47
Aug-94	$16.69	$15.01	$0.15	$0.15	$16.81	-$0.13
Sep-94	$16.11	$14.57	$0.15	$0.15	$16.37	-$0.26
Oct-94	$16.01	$14.44	$0.15	$0.15	$16.24	-$0.23

Date	West Coast ANS at 29° API ($/bbl.)	Wilmington at 17° API ($/bbl.)	Gravity Adjustment 0-19° API ($/deg. API)[A]	Gravity Adjustment 20-33°API ($/deg. API)[A]	Wilmington Adjusted to 29° API ($/bbl.)	Difference ANS - Wilm. at 29° API ($/bbl.)
	[1]	[2]	[3]	[4]	[5] = [2]+3*[3]+9*[4]	[6]=[1]-[5]
Nov-94	$16.64	$14.17	$0.15	$0.15	$15.97	$0.67
Dec-94	$15.50	$13.82	$0.15	$0.15	$15.62	-$0.12
Jan-95	$16.21	$13.93	$0.15	$0.15	$15.73	$0.48
Feb-95	$17.19	$14.31	$0.15	$0.15	$16.11	$1.08
Mar-95	$17.29	$14.30	$0.15	$0.15	$16.08	$1.21
Apr-95	$18.37	$15.39	$0.10	$0.10	$16.59	$1.78
May-95	$18.37	$16.29	$0.10	$0.10	$17.49	$0.87
Jun-95	$17.47	$15.86	$0.10	$0.10	$17.06	$0.41
Jul-95	$16.27	$14.47	$0.10	$0.10	$15.67	$0.60
Aug-95	$16.70	$14.46	$0.10	$0.10	$15.66	$1.03
Sep-95	$16.68	$14.79	$0.10	$0.10	$15.99	$0.69
Oct-95	$15.96	$14.04	$0.10	$0.10	$15.24	$0.71
Nov-95	$15.89	$13.75	$0.14	$0.14	$15.39	$0.50
Dec-95	$17.03	$14.20	$0.15	$0.15	$16.00	$1.03
Jan-96	$17.29	$15.22	$0.12	$0.12	$16.69	$0.60
Feb-96	$17.83	$15.41	$0.10	$0.10	$16.61	$1.22
Mar-96	$20.35	$17.63	$0.10	$0.10	$18.83	$1.52
Apr-96	$22.01	$19.24	$0.15	$0.15	$20.98	$1.03
May-96	$19.60	$16.02	$0.20	$0.20	$18.42	$1.17
Jun-96	$18.95	$15.27	$0.20	$0.20	$17.67	$1.28
Jul-96	$19.74	$15.67	$0.23	$0.23	$18.40	$1.34
Aug-96	$19.94	$15.81	$0.25	$0.25	$18.81	$1.13
Sep-96	$21.71	$17.36	$0.25	$0.25	$20.36	$1.35
Oct-96	$22.58	$18.61	$0.25	$0.25	$21.61	$0.97
Nov-96	$21.40	$18.05	$0.21	$0.21	$20.53	$0.86
Dec-96	$23.57	$19.71	$0.20	$0.20	$22.11	$1.46
Jan-97	$23.62	$20.32	$0.20	$0.20	$22.72	$0.90
Feb-97	$21.07	$17.62	$0.24	$0.24	$20.49	$0.58
Mar-97	$20.08	$16.72	$0.21	$0.21	$19.24	$0.84
Apr-97	$18.48	$16.11	$0.20	$0.20	$18.51	-$0.04
May-97	$19.32	$16.51	$0.13	$0.13	$18.12	$1.20
Jun-97	$17.26	$15.22	$0.15	$0.15	$17.02	$0.24
Jul-97	$17.51	$14.99	$0.15	$0.15	$16.75	$0.75
Aug-97	$18.01	$15.80	$0.10	$0.10	$17.00	$1.01
Sep-97	$18.12	$15.85	$0.10	$0.10	$17.05	$1.07
Oct-97	$19.60	$16.92	$0.10	$0.10	$18.12	$1.48
Nov-97	$18.34	$15.49	$0.10	$0.10	$16.69	$1.64
Dec-97	$16.43	$13.90	$0.10	$0.10	$15.10	$1.32
Jan-98	$14.78	$11.59	$0.12	$0.12	$13.00	$1.78
Feb-98	$13.37	$10.12	$0.16	$0.16	$12.05	$1.32
Mar-98	$12.27	$9.00	$0.18	$0.18	$11.15	$1.13
Apr-98	$12.53	$9.28	$0.15	$0.15	$11.08	$1.45
May-98	$12.33	$8.94	$0.15	$0.15	$10.74	$1.59
Jun-98	$11.67	$8.18	$0.15	$0.15	$9.98	$1.70
Jul-98	$13.02	$9.34	$0.15	$0.15	$11.14	$1.88
Aug-98	$12.55	$9.44	$0.15	$0.15	$11.24	$1.31
Sep-98	$14.19	$10.59	$0.15	$0.15	$12.39	$1.80
Oct-98	$13.42	$10.65	$0.15	$0.15	$12.45	$0.97
Nov-98	$11.51	$9.52	$0.15	$0.15	$11.30	$0.21
Dec-98	$9.36	$7.26	$0.10	$0.10	$8.46	$0.90
Jan-99	$10.78	$7.85	$0.10	$0.10	$9.05	$1.74
Feb-99	$10.47	$7.83	$0.10	$0.10	$9.03	$1.44
Mar-99	$13.08	$9.37	$0.12	$0.12	$10.86	$2.22
Apr-99	$15.61	$11.80	$0.15	$0.15	$13.60	$2.01
May-99	$15.83	$12.69	$0.15	$0.15	$14.49	$1.34

Date	West Coast ANS at 29° API ($/bbl.)	Wilmington at 17° API ($/bbl.)	Gravity Adjustment 0-19° API ($/deg. API)[A]	Gravity Adjustment 20-33°API ($/deg. API)[A]	Wilmington Adjusted to 29° API ($/bbl.)	Difference ANS - Wilm. at 29° API ($/bbl.)
	[1]	[2]	[3]	[4]	[5] = [2]+3*[3]+9*[4]	[6]=[1]-[5]
Jun-99	$15.92	$12.26	$0.15	$0.15	$14.06	$1.86
Jul-99	$18.36	$14.36	$0.15	$0.15	$16.16	$2.20
Aug-99	$20.20	$16.19	$0.19	$0.19	$18.49	$1.71
Sep-99	$22.90	$18.89	$0.20	$0.20	$21.29	$1.60
Oct-99	$21.84	$18.77	$0.20	$0.20	$21.17	$0.67
Nov-99	$23.61	$19.85	$0.20	$0.20	$22.25	$1.36
Dec-99	$24.53	$21.15	$0.20	$0.20	$23.55	$0.98
Average	$17.39	$14.35	$0.17	$0.17	$16.36	
					mean difference	$1.03
					min difference	-$0.68
					max difference	$3.02
					std dev difference	$0.74

Sources: [1],[2]: Reuters
[3],[4]: Chevron Posted Price Bulletins

Notes : A: When multiple gravity adjustments are given in a month, a daily weighted average adjustment is computed.

Table B-4

Comparison of Reuters Spot Prices: ANS and Kern River

Date	West Coast ANS at 29° API ($/bbl.) [1]	Kern River at 13° API ($/bbl.) [2]	Gravity Adjustment 0-19° API ($/deg. API)[A] [3]	Gravity Adjustment 20-33° API ($/deg. API)[A] [4]	Kern River Adjusted to 29° API ($/bbl.) [5] = [2]+7*[3]+9*[4]	Difference ANS - Kern at 29° API ($/bbl.) [6]=[1]-[5]
Jul-90	$15.52	$9.39	$0.20	$0.20	$12.56	$2.96
Aug-90	$26.01	$20.64	$0.29	$0.29	$25.32	$0.69
Sep-90	$31.95	$23.78	$0.30	$0.30	$28.53	$3.42
Oct-90	$31.59	$24.99	$0.32	$0.32	$30.08	$1.51
Nov-90	$28.72	$22.15	$0.25	$0.25	$26.15	$2.57
Dec-90	$23.71	$17.26	$0.34	$0.34	$22.75	$0.96
Jan-91	$20.74	$15.37	$0.23	$0.23	$19.08	$1.66
Feb-91	$15.70	$11.57	$0.25	$0.25	$15.57	$0.13
Mar-91	$16.99	$10.93	$0.25	$0.25	$14.93	$2.06
Apr-91	$17.58	$11.83	$0.25	$0.25	$15.83	$1.75
May-91	$16.73	$12.35	$0.25	$0.25	$16.35	$0.38
Jun-91	$16.29	$12.30	$0.21	$0.21	$15.66	$0.62
Jul-91	$17.33	$12.08	$0.20	$0.20	$15.34	$2.00
Aug-91	$17.18	$12.01	$0.25	$0.25	$16.01	$1.18
Sep-91	$17.35	$11.91	$0.25	$0.25	$15.91	$1.45
Oct-91	$18.54	$12.20	$0.27	$0.27	$16.58	$1.96
Nov-91	$17.46	$12.50	$0.25	$0.25	$16.50	$0.96
Dec-91	$14.88	$10.83	$0.15	$0.15	$13.23	$1.65
Jan-92	$14.94	$9.89	$0.15	$0.15	$12.29	$2.65
Feb-92	$15.33	$9.96	$0.15	$0.15	$12.36	$2.97
Mar-92	$15.49	$9.89	$0.15	$0.15	$12.29	$3.20
Apr-92	$16.97	$11.05	$0.15	$0.15	$13.45	$3.52
May-92	$18.09	$13.25	$0.15	$0.15	$15.65	$2.45
Jun-92	$20.23	$15.66	$0.15	$0.15	$18.06	$2.17
Jul-92	$19.42	$15.99	$0.15	$0.15	$18.39	$1.03
Aug-92	$18.00	$14.75	$0.15	$0.15	$17.15	$0.85
Sep-92	$18.48	$14.28	$0.15	$0.15	$16.68	$1.80
Oct-92	$18.80	$14.11	$0.15	$0.15	$16.57	$2.23
Nov-92	$17.42	$13.02	$0.19	$0.19	$16.06	$1.36
Dec-92	$16.37	$11.94	$0.15	$0.15	$14.34	$2.03
Jan-93	$15.59	$11.43	$0.15	$0.15	$13.83	$1.76
Feb-93	$16.81	$11.78	$0.15	$0.15	$14.18	$2.63
Mar-93	$17.38	$12.41	$0.15	$0.15	$14.81	$2.56
Apr-93	$18.22	$13.10	$0.15	$0.15	$15.50	$2.72
May-93	$17.46	$13.93	$0.15	$0.15	$16.33	$1.13
Jun-93	$16.04	$13.18	$0.15	$0.15	$15.58	$0.46
Jul-93	$14.79	$11.10	$0.15	$0.15	$13.50	$1.29
Aug-93	$15.44	$10.96	$0.15	$0.15	$13.36	$2.08
Sep-93	$15.01	$10.81	$0.15	$0.15	$13.21	$1.80
Oct-93	$15.45	$11.29	$0.15	$0.15	$13.69	$1.76
Nov-93	$13.02	$10.15	$0.15	$0.15	$12.55	$0.48
Dec-93	$10.39	$8.17	$0.15	$0.15	$10.57	-$0.18
Jan-94	$11.64	$8.10	$0.15	$0.15	$10.50	$1.15
Feb-94	$12.56	$8.87	$0.15	$0.15	$11.27	$1.30
Mar-94	$12.86	$9.24	$0.15	$0.15	$11.64	$1.22
Apr-94	$14.91	$10.23	$0.15	$0.15	$12.63	$2.28
May-94	$16.41	$11.70	$0.15	$0.15	$14.10	$2.31
Jun-94	$16.46	$12.92	$0.14	$0.14	$15.18	$1.27
Jul-94	$16.54	$13.28	$0.13	$0.13	$15.37	$1.16
Aug-94	$16.69	$14.06	$0.15	$0.15	$16.46	$0.22
Sep-94	$16.11	$13.56	$0.15	$0.15	$15.96	$0.16

Date	West Coast ANS at 29° API ($/bbl.)	Kern River at 13° API ($/bbl.)	Gravity Adjustment 0-19° API ($/deg. API)[A]	Gravity Adjustment 20-33° API ($/deg. API)[A]	Kern River Adjusted to 29° API ($/bbl.)	Difference ANS - Kern at 29° API ($/bbl.)
	[1]	[2]	[3]	[4]	[5] = [2]+7*[3]+9*[4]	[6]=[1]-[5]
Oct-94	$16.01	$13.06	$0.15	$0.15	$15.46	$0.55
Nov-94	$16.64	$12.82	$0.15	$0.15	$15.22	$1.42
Dec-94	$15.50	$12.41	$0.15	$0.15	$14.81	$0.69
Jan-95	$16.21	$12.47	$0.15	$0.15	$14.87	$1.34
Feb-95	$17.19	$12.94	$0.15	$0.15	$15.34	$1.85
Mar-95	$17.29	$13.35	$0.15	$0.15	$15.72	$1.57
Apr-95	$18.37	$14.48	$0.10	$0.10	$16.08	$2.29
May-95	$18.37	$15.30	$0.10	$0.10	$16.90	$1.47
Jun-95	$17.47	$15.07	$0.10	$0.10	$16.67	$0.80
Jul-95	$16.27	$14.08	$0.10	$0.10	$15.68	$0.59
Aug-95	$16.70	$13.57	$0.10	$0.10	$15.17	$1.53
Sep-95	$16.68	$13.78	$0.10	$0.10	$15.38	$1.30
Oct-95	$15.96	$12.62	$0.10	$0.10	$14.22	$1.74
Nov-95	$15.89	$12.30	$0.14	$0.14	$14.49	$1.40
Dec-95	$17.03	$12.77	$0.15	$0.15	$15.17	$1.86
Jan-96	$17.29	$14.08	$0.12	$0.12	$16.04	$1.24
Feb-96	$17.83	$14.33	$0.10	$0.10	$15.93	$1.90
Mar-96	$20.35	$16.57	$0.10	$0.10	$18.17	$2.18
Apr-96	$22.01	$18.00	$0.15	$0.15	$20.32	$1.68
May-96	$19.60	$14.89	$0.20	$0.20	$18.09	$1.51
Jun-96	$18.95	$14.08	$0.20	$0.20	$17.28	$1.67
Jul-96	$19.74	$13.82	$0.23	$0.23	$17.46	$2.28
Aug-96	$19.94	$13.95	$0.25	$0.25	$17.95	$1.99
Sep-96	$21.71	$15.77	$0.25	$0.25	$19.77	$1.94
Oct-96	$22.58	$17.23	$0.25	$0.25	$21.23	$1.35
Nov-96	$21.40	$16.68	$0.21	$0.21	$19.98	$1.42
Dec-96	$23.57	$18.22	$0.20	$0.20	$21.42	$2.16
Jan-97	$23.62	$18.73	$0.20	$0.20	$21.93	$1.69
Feb-97	$21.07	$14.99	$0.24	$0.24	$18.82	$2.25
Mar-97	$20.08	$14.58	$0.21	$0.21	$17.93	$2.15
Apr-97	$18.48	$14.30	$0.20	$0.20	$17.50	$0.97
May-97	$19.32	$14.68	$0.13	$0.13	$16.82	$2.50
Jun-97	$17.26	$13.64	$0.15	$0.15	$16.04	$1.22
Jul-97	$17.51	$13.59	$0.15	$0.15	$15.93	$1.57
Aug-97	$18.01	$14.59	$0.10	$0.10	$16.19	$1.82
Sep-97	$18.12	$14.80	$0.10	$0.10	$16.40	$1.72
Oct-97	$19.60	$15.96	$0.10	$0.10	$17.56	$2.04
Nov-97	$18.34	$14.31	$0.10	$0.10	$15.91	$2.43
Dec-97	$16.43	$12.65	$0.10	$0.10	$14.25	$2.17
Jan-98	$14.78	$10.32	$0.12	$0.12	$12.21	$2.58
Feb-98	$13.37	$8.47	$0.16	$0.16	$11.04	$2.33
Mar-98	$12.27	$6.90	$0.18	$0.18	$9.76	$2.51
Apr-98	$12.53	$7.65	$0.15	$0.15	$10.05	$2.48
May-98	$12.33	$7.81	$0.15	$0.15	$10.21	$2.12
Jun-98	$11.67	$7.18	$0.15	$0.15	$9.58	$2.09
Jul-98	$13.02	$8.24	$0.15	$0.15	$10.64	$2.38
Aug-98	$12.55	$8.29	$0.15	$0.15	$10.69	$1.86
Sep-98	$14.19	$9.39	$0.15	$0.15	$11.79	$2.40
Oct-98	$13.42	$9.75	$0.15	$0.15	$12.15	$1.27
Nov-98	$11.51	$8.49	$0.15	$0.15	$10.87	$0.64
Dec-98	$9.36	$6.53	$0.10	$0.10	$8.13	$1.23
Jan-99	$10.78	$7.13	$0.10	$0.10	$8.73	$2.05
Feb-99	$10.47	$7.08	$0.10	$0.10	$8.68	$1.79
Mar-99	$13.08	$8.56	$0.12	$0.12	$10.55	$2.53
Apr-99	$15.61	$10.95	$0.15	$0.15	$13.35	$2.26

Date	West Coast ANS at 29° API ($/bbl.)	Kern River at 13° API ($/bbl.)	Gravity Adjustment 0-19° API ($/deg. API)[A]	Gravity Adjustment 20-33° API ($/deg. API)[A]	Kern River Adjusted to 29° API ($/bbl.)	Difference ANS - Kern at 29° API ($/bbl.)
	[1]	[2]	[3]	[4]	[5] = [2]+7*[3]+9*[4]	[6]=[1]-[5]
May-99	$15.83	$11.79	$0.15	$0.15	$14.19	$1.64
Jun-99	$15.92	$11.19	$0.15	$0.15	$13.59	$2.33
Jul-99	$18.36	$13.37	$0.15	$0.15	$15.77	$2.58
Aug-99	$20.20	$15.29	$0.19	$0.19	$18.36	$1.84
Sep-99	$22.90	$17.92	$0.20	$0.20	$21.12	$1.78
Oct-99	$21.84	$17.81	$0.20	$0.20	$21.01	$0.82
Nov-99	$23.61	$18.83	$0.20	$0.20	$22.03	$1.57
Dec-99	$24.53	$20.00	$0.20	$0.20	$23.20	$1.33
Average	$17.39	$13.00	$0.17	$0.17	$15.68	
					mean difference	$1.71
					min difference	-$0.18
					max difference	$3.52
					std dev difference	$0.72

Sources: [1],[2]: Reuters
[3],[4]: Chevron Posted Price Bulletins

Notes : A: When multiple gravity adjustments are given in a month, a daily weighted average adjustment is comput

Table B-5
Representative Assays for Selected California Crude Oils*

Field	Sample Id.	Gravity ° API	Sulfur % Weight	Distillation Breakdown (Percent of Volume): Total Gasoline & Naptha	Middle Distillates	Residuum	Lubes
San Ardo	53059	12.2	2.25%	2.1%	14.5%	62.5%	20.5%
Midway Sunset	78031	12.6	1.61%	0.0%	12.0%	50.3%	34.8%
Kern River	461	13.3	1.14%	0.0%	15.8%	56.1%	28.1%
Mount Poso	55150	16.0	0.68%	0.0%	13.4%	52.0%	34.0%
Wilmington	77025	17.1	1.66%	9.5%	18.2%	52.8%	19.4%
Lost Hills	1099	18.4	0.99%	7.6%	23.5%	42.7%	23.2%
Huntington Beach	23517	19.4	2.00%	12.0%	19.7%	48.9%	19.4%
Inglewood	43031	21.0	1.84%	12.9%	27.6%	39.1%	19.4%
Long Beach	1138	25.0	1.25%	18.9%	23.1%	40.6%	17.4%
Dos Cuadros	69230	25.0	1.14%	21.0%	21.5%	39.0%	17.9%
Ventura	55128	30.2	1.00%	30.2%	20.8%	31.3%	16.3%
Belridge N. Lt.	46049	31.3	0.28%	25.7%	25.7%	26.3%	20.9%
Elk Hills	80006	34.6	0.76%	34.3%	23.3%	25.0%	15.9%

* These assays were selected from assay data from the DOE Laboratory in Bartlesville, Oklahoma. Some of these dat date back several decades. Criteria for selection were API gravity similar to oil currently produced in the field and th the assay was in general representative of the population of assays for the given field.

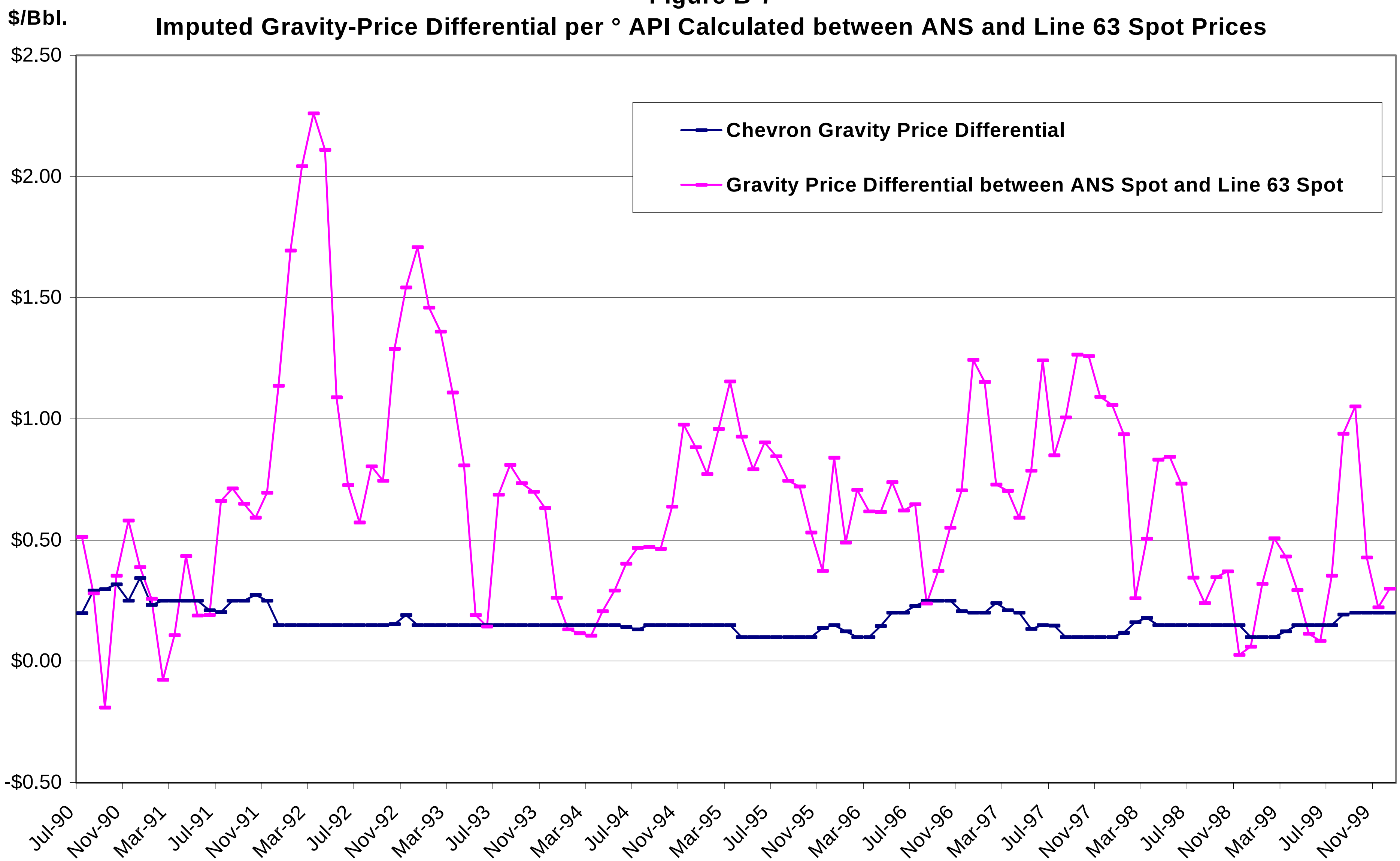
Table B-6
Heavy and Light Oil Production for the State of California in the Month of January

	Production in barrels per day		Percentage of State Production	
	Heavy Oil[A] Production	**Light Oil[B] Production**	**Heavy Oil Production**	**Light Oil Production**
	bbl/day	*bbl/day*		
1990	679,015	292,378	69.9%	30.1%
1991	661,411	287,556	69.7%	30.3%
1992	655,719	294,133	69.0%	31.0%
1993	622,924	302,418	67.3%	32.7%
1994	627,405	296,106	67.9%	32.1%
1995	644,726	308,751	67.6%	32.4%
1996	664,981	286,446	69.9%	30.1%
1997	656,415	255,981	71.9%	28.1%
1998	659,300	274,656	70.6%	29.4%

A: Heavy oil has gravity of 20° API and below.
B: Light oil has gravity of over 20° API.
Source: 1998 Annual Report of the State Oil and Gas Supervisor, California Department of Conservation, Division of Oil, Gas and Geothermal Resources.

Figure B-7

Imputed Gravity-Price Differential per ° API Calculated between ANS and Line 63 Spot Prices



Source: Reuters (Spot Prices) and Chevron Posted Price Bulletins (Chevron Gravity-Price Differential).
Notes: The Gravity-Price Differential between ANS Spot and Line 63 Spot is calculated as the difference in price between the two spot prices divided by the difference in degrees of API gravity between the two prices to arrive at an Imputed Gravity-Price differential per degree API.

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Appendix C
Gravity Price Adjustments for Adjacent Fields

The examples listed below are comparisons of crude oil fields not of the same gravity, but located adjacent to one another or within ten miles of one another so that transportation should not be an issue in price differences. Gravity price differentials were applied to see if a gravity price adjustment is able to account for all differences in price. For crude oil prices, gravities, and gravity adjustments, the Tosco/Union posting bulletin for September 3, 1998 was used.

<u>Example 1</u>

Midway Sunset	13°	$ 8.75
Buena Vista	26°	$11.00

Adjusted to 26 / $0.15 for every degree

Midway Sunset	26°	$10.70
Buena Vista	26°	$11.00

Unaccounted for Difference = $0.30

<u>Example 2</u>

Wilmington	17°	$ 9.25
LB (Signal Hill)	29°	$11.65

Adjusted to 29 / $0.15 for every degree

Wilmington	29°	$11.05
LB (Signal Hill)	29°	$11.65

Unaccounted for Difference = $0.60

<u>Example 3</u>

Newhall Potrero	32°	$12.00
Del Valle	33°	$11.45

Adjusted to 33 / $0.15 for every degree

Newhall Potrero	33°	$12.15
Del Valle	33°	$11.45

Unaccounted for Difference = $0.70

<u>Example 4</u>

Yorba Linda	15°	$ 8.75
Brea Olinda	20°	$10.60

<u>*Adjusted to 20 / $0.15 for every degree*</u>

Yorba Linda	20°	$ 9.50
Brea Olinda	20°	$10.60

Unaccounted for Difference = $1.10

<u>Example 5</u>

Cat Canyon	11°	$ 5.60
Orcutt	25°	$ 8.55

Adjusted to 25 / $0.15 for every degree

Cat Canyon	25°	$ 7.70
Orcutt	25°	$ 8.55

Unaccounted for Difference = $0.85

Appendix D
Sources of Crude Oil Spot Prices

Reuters

Methodology
Reuters prices are collected by a reporter on a daily basis. The Reuters reporter contacts market participants inquiring about current prices and ranges. The data is collected and is published as a daily high and low. The closing price for the crude oils is the mean of the daily high and low.

Reuters provides West Coast crude oil spot price information for the following crude oils:
<u>Line 63</u>, with gravity 28.0 degrees API, and sulfur 1 pct.
<u>ANS delivered to the West Coast</u>, with gravity 29.0 degrees API and sulfur 1.1 pct.
<u>Wilmington</u>, with gravity 17.0 degrees API and sulfur 1.5 pct.
<u>Kern River</u>, with gravity 13.0 degrees API and sulfur 1.2 pct.

Reuters also reports on spot price differentials and spot price in terms of premium to posting:
<u>Line 63 vs. Differential</u>
<u>ANS vs. Last Repeated Bid</u>
<u>Wilmington Premium to Posting</u>
<u>Kern River Premium to posting</u>

Platt's

Methodology
There are general principles that underlie Platt's approach to market reporting. For example, Platt's generally looks for fixed-price spot transactions, confirmed bids and offers, market talk and relationships, if any, with other markets. Platt's reporters also generally look at the characteristics of individual markets and the foregoing methodology may be adapted especially in cases where fixed-price liquidity is lacking.

Platt's prices are published in three daily publications: *Platt's Oilgram News*, *Platt's Oilgram Price Report* and *Platt's Crude Oil Marketwire*. A high and low range of prices is published daily in the *Platt's Crude Oil Marketwire*. Prices are reported in a five-day rolling average format in the *Platt's Oilgram Price Report* (a weekly publication). Also Platt's puts out a monthly crude oil supplement, *Platt's Crude Oil Supplement*, which reports a simple average for the month of the daily low, high and mean prices.

Platt's provides West Coast crude oil spot price information on the following crude oils:
<u>Alaska North Slope (ANS)</u>: California barrels are for delivery to Long Beach, California. API Gravity is 29-29.5 and sulfur content is 1.1 pct.
<u>Line 63</u>: The assessment is for a blend of crude at 28-30 degrees API gravity and sulfur content of 1.02 pct. Delivered at Hynes station on Four Corners' pipeline line 63.

P-Plus Line 63: The assessment reflects the price of Line 63 sold into Hynes Station on Four Corners' pipeline on the basis of "Posting Plus." P-Plus deals are invoiced at a later date on the basis of a differential to an average of one or more crude postings for Buena Vista.
Thums: The assessment is for barrels of Wilmington delivered to Long Beach, California at 17 degrees API and sulfur content of 1.5 pct.
Kern River: The assessment is for barrels delivered commonly to Texaco's station 31 in Kern County, California, at 13.4 degrees API gravity with sulfur content of 1.1 pct. Synonymous with San Joaquin Valley (SJV) heavy.

Telerate

Methodology
Spot prices are assessments – subjective by their nature – published under the Telerate Energy banner by Bridge News and by Dow Jones Newswires jointly with Telerate Energy. Assessments are the results of reporters' wide survey of market participants and likely include, depending on market conditions, elements of transactions, bids, offers, "indications," "talking levels," or differentials vs. other active grades. Assessments typically conform to standard calendar periods, quantities and qualities.

Telerate reports on the following spot crude oil prices:
Kern River, This is San Joaquin Valley Heavy crude oil and is typically the spot price for Kern River or Midway Sunset. The gravity is 13 degrees API and the sulfur is 1.0 pct.
Thums, This is typically a spot assessment of Wilmington crude oil at a gravity of 17 degrees API and a sulfur of 1.5 pct.
Line 63 CIF LA, This is a spot assessment of Line 63 crude oil at 28 degrees API and sulfur of 1.0 pct.
ANS CIF LA, This is a spot assessment of ANS crude at a gravity of 29 degrees API and sulfur of 1.1 pct.

Also attached is a table comparing ANS spot prices from Reuters with spot prices from Platt's. The average difference between these two price series is $0.01.

Attachment to Appendix D
Spot Price Comparison for ANS (Reuters and Platts)

	Reuters West Coast ANS at 29° API ($/bbl.)	Platt's West Coast ANS at 29-29.5° API ($/bbl.)	Difference Reuters Less Platts
	[1]	[2]	[3] = [1] - [2]
Jan-94	$11.64	$11.60	$0.04
Feb-94	$12.56	$12.57	-$0.01
Mar-94	$12.86	$12.91	-$0.05
Apr-94	$14.91	$14.83	$0.08
May-94	$16.41	$16.54	-$0.13
Jun-94	$16.46	$16.47	-$0.02
Jul-94	$16.54	$16.54	$0.00
Aug-94	$16.69	$16.60	$0.09
Sep-94	$16.11	$16.10	$0.01
Oct-94	$16.01	$16.08	-$0.07
Nov-94	$16.64	$16.71	-$0.07
Dec-94	$15.50	$15.38	$0.12
Jan-95	$16.21	$16.16	$0.05
Feb-95	$17.19	$17.14	$0.05
Mar-95	$17.29	$17.32	-$0.03
Apr-95	$18.37	$18.38	-$0.01
May-95	$18.37	$18.35	$0.02
Jun-95	$17.47	$17.44	$0.03
Jul-95	$16.27	$16.25	$0.02
Aug-95	$16.70	$16.72	-$0.02
Sep-95	$16.68	$16.65	$0.03
Oct-95	$15.96	$15.96	$0.00
Nov-95	$15.89	$15.87	$0.02
Dec-95	$17.03	$16.94	$0.09
Jan-96	$17.29	$17.23	$0.06
Feb-96	$17.83	$17.78	$0.05
Mar-96	$20.35	$20.40	-$0.05
Apr-96	$22.01	$22.04	-$0.03
May-96	$19.60	$19.65	-$0.05
Jun-96	$18.95	$18.98	-$0.03
Jul-96	$19.74	$19.74	$0.00
Aug-96	$19.94	$19.97	-$0.03
Sep-96	$21.71	$21.73	-$0.02
Oct-96	$22.58	$22.60	-$0.02
Nov-96	$21.40	$21.50	-$0.10
Dec-96	$23.57	$23.66	-$0.09
Jan-97	$23.62	$23.58	$0.04
Feb-97	$21.07	$21.03	$0.04
Mar-97	$20.08	$20.07	$0.01
Apr-97	$18.48	$18.54	-$0.06
May-97	$19.32	$19.41	-$0.09
Jun-97	$17.26	$17.30	-$0.04
Jul-97	$17.51	$17.48	$0.03

	[1]	[2]	[3] = [1] - [2]
Aug-97	$18.01	$17.98	$0.03
Sep-97	$18.12	$18.09	$0.03
Oct-97	$19.60	$19.59	$0.01
Nov-97	$18.34	$18.33	$0.01
Dec-97	$16.43	$16.39	$0.04
Jan-98	$14.78	$14.79	-$0.01
Feb-98	$13.37	$13.39	-$0.02
Mar-98	$12.27	$12.25	$0.02
Apr-98	$12.53	$12.42	$0.11
May-98	$12.33	$12.31	$0.02
Jun-98	$11.67	$11.62	$0.05
Jul-98	$13.02	$12.92	$0.10
Aug-98	$12.55	$12.49	$0.06
Sep-98	$14.19	$14.13	$0.06
Oct-98	$13.42	$13.38	$0.04
Nov-98	$11.51	$11.47	$0.04
Dec-98	$9.36	$9.39	-$0.03
Jan-99	$10.78	$10.69	$0.09
Feb-99	$10.47	$10.43	$0.04
Mar-99	$13.08	$13.06	$0.02
Apr-99	$15.61	$15.64	-$0.03
May-99	$15.83	$15.86	-$0.03
Jun-99	$15.92	$15.84	$0.08
Jul-99	$18.36	$18.16	$0.20
		Average	$0.01
		Maximum	$0.20
		Minimum	-$0.13
		StdDev	$0.06